BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

DOCKET NO. 2018-318-E

In the Matter of:	)	
	)	**DUKE ENERGY PROGRESS,**
Application of Duke Energy Progress, LLC	)	**LLC'S PROPOSED ORDER**
for Adjustments in Electric Rate Schedules	)	
and Tariffs	)	

I. INTRODUCTION AND PROCEDURAL HISTORY

This matter comes before the Public Service Commission of South Carolina (the "Commission" or "PSCSC") on the Application of Duke Energy Progress, LLC ("DE Progress" or the "Company") filed November 8, 2018 (the "Application") requesting authority to adjust and increase its electric rates, charges, and tariffs. The Application was filed pursuant to S.C. Code Ann. §§ 58-27-820 and 58-27-870 and 26 S.C. Code Ann. Regs. 103-303 and 103-823.

Along with its Application, on November 8, 2018, the Company filed the direct testimony of Laura A. Bateman, Director of Rates and Regulatory for DE Carolinas; David L. Doss, Jr., Director of Electric Utilities and Infrastructure Accounting for Duke Energy Business Services, LLC ("DEBS")[1]; Kodwo Ghartey-Tagoe, State President – South Carolina for Duke Energy Carolinas, LLC ("DE Carolinas") and DE Progress; Janice Hager, President of Janice Hager Consulting, LLC; Kelvin Henderson, Senior Vice President of Nuclear Operations for Duke Energy Corporation ("Duke Energy"); Robert B. Hevert, Partner at ScottMadden, Inc.; Retha

[1] DEBS provides various administrative and other services to DE Progress and other affiliated companies of Duke Energy.

Hunsicker, Vice President, Customer Connect-Solutions for DEBS; Jon F. Kerin, Vice President, Coal Combustion Products ("CCP") Operations, Maintenance and Governance for DEBS; Joseph A. Miller, Jr., Vice President of Central Services for DEBS; Jay W. Oliver, General Manager, Grid Solutions Engineering and Technology for DEBS; John Panizza, Director Tax Operations for DEBS; Donald Schneider, Jr., General Manager, Advanced Metering Infrastructure ("AMI") Program Management for DEBS; John L. Sullivan, III, Director, Corporate Finance and Assistant Treasurer for DEBS and Assistant Treasurer of DE Carolinas; Kendra Ward, Rates and Regulatory Strategy Manager for Duke Energy; Stephen B. Wheeler, Pricing & Regulatory Solutions Director for DEBS, and Dr. Julius A. Wright, Managing Partner, J.A. Wright & Associates, LLC. Exhibits were included with the direct testimony of witnesses Bateman, Doss, Hevert, Hunsicker, Kerin, Oliver, Ward, and Wheeler.

The Company filed supplemental direct testimony and exhibits for Company witness Bateman on January 18, 2019 and January 22, 2019.

The Company's general electric rates and charges were last approved by the Commission in Docket No. 2016-227-E, Order No. 2016-871, dated December 21, 2016.

In its Application, the Company requested a revenue increase of approximately $59 million[2] and a return on equity ("ROE") of 10.50%.

On November 26, 2018, the Commission Clerk's Office issued the Notice of Filing and Hearing and instructed the Company to publish it in newspapers of general circulation in the areas affected by the Company's Application by December 6, 2018, to notify each affected customer of the hearing by December 6, 2018, and provide a certification to the Commission by December

[2] The net annual revenue increase includes the impact of the return of deferred income taxes through the excess deferred income tax rider ("EDIT Rider") of approximately $10 million, as discussed below.

27, 2018. On November 27, 2018, the Company filed a letter requesting additional time to complete the notification to customers. On November 28, 2018, the Commission's Docketing Department issued a Revised Notice of Filing and Hearing and instructed the Company to publish it in newspapers of general circulation in the areas affected by the Company's Application by December 6, 2018, and to provide proof of publication by December 27, 2018. The Revised Notice of Filing and Hearing indicated the revenue being requested by the Company, the overall impact to residential customers, and other important details and references necessary to advise the public of the breadth and nature of the Company's request. The Revised Notice of Filing and Hearing also advised those desiring to participate in the proceeding, scheduled to begin April 11, 2019, of the manner and time in which to file appropriate pleadings. The Company also had to notify each affected customer of the hearing by January 11, 2019, and provide a certification to the Commission by February 1, 2019. On December 27, 2018, the Company filed affidavits with the Commission demonstrating that the Revised Notice was duly published in accordance with the Docketing Department's instructions. On January 31, 2019, the Company filed an affidavit certifying that the Revised Notice of Filing and Hearing had been furnished to all applicable customers of DE Progress.

Pursuant to Commission Order No. 2019-120, the Docketing Department scheduled public hearings[3] in the Counties of Florence and Sumter. On February 20, 2019, the Commission's Docketing Department instructed the Company to notify each affected customer of the Public Night Hearings by March 1, 2019. DE Progress requested that, in lieu of mailing customers Notice of the Public Night Hearings, it be permitted to provide notice of the hearings using the Company's

[3] The purpose of the night hearings was to provide a forum, at a convenient time and location, for customers of DE Progress to present their comments regarding the service and rates.

automated calling system to place calls to customers to be completed by March 1, 2019, informing them of the dates, times, and locations of both hearings. On February 21, 2019, pursuant to Commission Order No. 2019-19-H, the Standing Hearing Officer granted the Company's request for approval of alternative notice of public night hearings.

Walmart Inc. ("Walmart"), represented by Stephanie U. Eaton, Esquire, Carrie Harris Grundmann, Esquire, and Derrick Price Williamson, Esquire, filed a petition to intervene on November 27, 2018. On December 17, 2018, Nucor Steel – South Carolina ("Nucor"), represented by Michael K. Lavanga, Esquire, Robert R. Smith, II, Esquire, and Garrett A. Stone, Esquire, filed a petition to intervene. Vote Solar, represented by William C. Dillard, Jr., Esquire, Bess J. Durant, Esquire and Thadeus B. Culley, Esquire, filed a petition to intervene on December 27, 2018. The South Carolina Solar Business Alliance ("SCSBA") represented by Richard L. Whitt, Esquire, filed a petition to intervene on January 2, 2019. Cypress Creek Renewables, LLC ("Cypress Creek"), represented by Richard L. Whitt, Esquire, filed a petition to intervene on January 18, 2019. Sierra Club, represented by Robert Guild, Esquire and Bridget Lee, Esquire, filed a petition to intervene on January 28, 2019. The South Carolina Energy Users Committee ("SCEUC") represented by Scott Elliott, Esquire, filed a petition to intervene on January 28, 2019. The South Carolina State Conference of the National Association for the Advancement of Colored People, South Carolina Coastal Conservation League, and Upstate Forever (collectively, "SC NAACP et al."), represented by Stinson Woodward Ferguson, Esquire; David L. Neal, Esquire; and Gudrun E. Thompson, Esquire, filed a petition to intervene on February 1, 2019. The South Carolina Department of Consumer Affairs ("Consumer Affairs"), exercising its right to intervene to advocate for the interest of consumers pursuant to S.C. Code Ann. § 37-6-604(C), was represented by Becky Dover, Esquire and Carri Grube-Lybarker, Esquire. The Office of Regulatory Staff

("ORS"), automatically a party pursuant to S.C. Code Ann. § 58-4-10(B), was represented by Andrew M. Bateman, Esquire; Alexander W. Knowles, Esquire; and Nanette S. Edwards, Esquire. DE Progress was represented by Heather Shirley Smith, Esquire; John T. Burnett, Esquire; Camal O. Robinson, Esquire; Frank R. Ellerbe, III, Esquire; Brandon F. Marzo, Esquire; Molly McIntosh Jagannathan, Esquire; and Len S. Anthony, Esquire. Collectively, DE Progress, Walmart, Nucor, Vote Solar, SCSBA, Cypress Creek, Sierra Club, SCEUC, SC NAACP et al., Consumer Affairs, and ORS are referred to as the "Parties" or individually as a "Party."

In Order No. 2019-153, issued on February 27, 2019, the Commission granted the Company's request for leave to file the direct testimony of Julie K. Turner, Vice President of Carolinas Natural Gas Generation for DE Progress, adopting the pre-filed direct testimony of Joseph A. Miller, Jr.

On March 1, 2019, SCSBA filed the direct testimony and exhibits of Hamilton Davis, Director of Regulatory Affairs for Southern Current, LLC, and Christopher Villarreal, President of Plugged In Strategies. On March 4, 2019, Nucor filed the direct testimony and exhibits of Dr. Jay Zernikau, Vice President of Frontier Energy, Jeffry Pollock, President of J. Pollock, Incorporated, and Billie S. LaConte, Associate Consultant at J. Pollock, Incorporated. Vote Solar filed the direct testimony and exhibits of Justin R. Barnes, Director of Research with EQ Research, LLC. On March 4, 2019, SC NAACP et al. filed the direct testimony and exhibits of John Howat, Senior Policy Analyst at the National Consumer Law Center, and Jonathan Wallach, Vice President of Resource Insight, Inc. On March 4, 2019, ORS filed the direct testimony of Willie J. Morgan, P.E., Deputy Director of the Utility Rates Department; David C. Parcell, Principal and Senior Economist of Technical Associates, Inc.; Zachary J. Payne, Senior Auditor in the Audit Department; Anthony Sandonato, Regulatory Analyst in the Utility Rates and Services Division;

Matthew P. Schellinger II, Regulatory Analyst in the Utility Rates and Services Division; Michael L. Seaman-Huynh, Senior Regulatory Manager in the Utility Rates and Services Division; Sarah W. Johnson, Deputy Director of Utility Services in the Utility Rates and Services Division; Kelvin L. Major, Audit Manager, and Dan J. Wittliff, Managing Director of Environmental Services for GDS Associates, Inc. Exhibits were included with the direct testimony of witnesses Morgan, Parcell, Seaman-Huynh, Major, and Wittliff. On March 4, 2019, Sierra Club filed the direct testimony and exhibits of Ezra D. Hausman, Ph.D., an independent consultant doing business as Ezra Hausman Consulting. Walmart filed the direct testimony and exhibits of Steve Chriss, its Director, Energy Services, on March 4, 2019. SCEUC filed the direct testimony and exhibits of Kevin W. O'Donnell, President of Nova Energy Consultants, Inc., on March 4, 2019.

On March 18, 2019, the Company filed the rebuttal testimony of witnesses Bateman; Barbara A. Coppola, Manager, Grid Solutions for DEBS; Ghartey-Tagoe; Hager; Henderson; Hevert;, Hunsicker; Kerin, Renee Metzler, Managing Director, Retirement and Health and Welfare for DEBS; Oliver; Panizza; Lesley Quick, Vice President, Revenue Services of Duke Energy; John J. Spanos, President, Gannett Fleming Valuation and Rate Consultants, LLC; Sullivan; Turner; Wheeler and Wright. Exhibits were included with the rebuttal testimony of witnesses Bateman, Hevert, Wheeler, Spanos and Sullivan.

On March 25, 2019, the Sierra Club filed the surrebuttal testimony of witness Hausman. On March 25, 2019, SC NAACP et al. filed the surrebuttal testimony of witnesses Howat and Wallach; Vote Solar filed the surrebuttal testimony of witness Barnes; and the ORS filed the surrebuttal testimony of witnesses Steven W. Hamm, Major, Morgan, Parcell, Payne, John C. Ruoff, Seaman-Huynh, and Wittliff. Exhibits were included with the surrebuttal testimony of Vote

Solar witness Barnes; ORS witnesses Major, Seaman-Huynh, Parcell, Wittliff, Ruoff, and Hamm; and SC NAACP, et. al. witness Howat.

On March 8, 2019, the ORS moved to establish a new and separate hearing docket to review and consider the Company's proposed Grid Improvement Plan ("GIP"). On March 12, 2019, ORS and DE Carolinas filed a Stipulation (the "GIP Stipulation") in Docket No. 2018-319-E, agreeing that the GIP shall be considered in a separate docket independent from the Application. By email, on March 13, 2019, counsel for DE Carolinas and DE Progress agreed to extend the same terms contained within the GIP Stipulation to DE Progress. As part of the GIP Stipulation, the Company agreed to withdraw from Commission consideration the GIP and the associated cost recovery proposal for costs incurred related to plant placed in service on or after January 1, 2019. Pursuant to the GIP Stipulation, all testimony and evidence relating to the GIP may be moved to the new docket, and all Parties who have expressed any position on the GIP shall automatically be granted intervenor status in the new docket. ORS and the Company further agreed that DE Progress may defer into a regulatory asset account all GIP-related costs until the underlying costs and proposed recovery may be considered in the next general rate case proceeding. On March 13, 2019, the Standing Hearing Officer approved the GIP Stipulation pursuant to Order No. 2019-26H.

On March 29, 2019, the Company filed a stipulation with Nucor (the "Nucor Stipulation," Hearing Exhibit #35) resolving the issues raised by Nucor in this proceeding, along with the supplemental testimony of DE Progress witness Wheeler in support of the Nucor Stipulation. As a result of the Nucor Stipulation, the Company and Nucor agreed to certain modifications to the Company's Excess Deferred Income Tax ("EDIT") rider and rate schedule LGS-CUR-TOU, and also agreed that Nucor would not seek a Commission decision on other issues addressed by the pre-filed testimony of the Nucor witnesses in this proceeding. (Hearing Ex. 35, p. 2.) As a result of the Nucor Stipulation, Nucor agreed to withdraw the direct testimony of Nucor witnesses Zernikau, LaConte and Pollock, and the Company agreed to withdraw the rebuttal testimony of Company witnesses Panizza and Spanos. (*Id.*) On April 1, 2019, the Company filed the revised rebuttal testimony of witnesses Bateman, Ghartey-Tagoe, Henderson, Hevert, and Sullivan, revised to remove the portions of their testimony filed in response to the Nucor's witnesses' pre-filed testimony.

On April 1, 2019, the Company filed the second supplemental direct testimony of witness Bateman with Bateman second supplemental Exhibit 3. On April 2, 2019, the Company filed the revised second supplemental Exhibit 3 to the testimony of witness Bateman and supplemental testimony of witness Kerin.

On April 9, 2019, ORS filed the revised surrebuttal testimony and exhibits of witness Hamm and other exhibits to the testimony of ORS witnesses Major and Morgan that were previously filed under seal, but that the Company agreed to make public.

On April 10, 2019, the ORS filed a stipulation with the Company (the "Prepaid Stipulation") in which the Company and ORS agreed that the Company's request regarding the Prepaid Advantage Pilot program ("Prepaid Advantage" or "Prepaid Pilot"), shall be considered in a separate docket independent from the Application. As part of the Prepaid Stipulation, the ORS and the Company agreed to withdraw from Commission consideration the Prepaid Pilot. Pursuant to the Prepaid Stipulation, all testimony and evidence relating to the Prepaid Pilot may be moved to the new docket, and all Parties who have expressed any position on the Prepaid Pilot shall automatically be granted intervenor status in the new docket. ORS and the Company further agreed that if DE Progress implements its Prepaid Pilot in the same manner as DE

Carolinas, ORS will not object to DE Progress' Prepaid Pilot or the Company seeking expedited review of its Prepaid Pilot.

Public hearings were held on April 1, 2019 in Florence County and April 2, 2019 in Sumter County. Hundreds of customers attended these hearings and spoke to the Commission about their concerns regarding the Company's proposal.

On April 10, 2019, the Standing Hearing Officer excused from the hearing SCSBA witnesses Davis and Villareal, who will testify in a subsequent hearing addressing the GIP. On April 11, 2019, the Commission excused from the hearing SC NAACP et al. witness Howat and his pre-filed verified testimony was entered into the record without the witness being required to appear in person at the hearing. On April 12, 2019, the Commission excused from the hearing Company witnesses Doss, Oliver and Ward and their pre-filed verified testimony was entered into the record as though given orally from the stand, without the witnesses being required to appear. On April 15, 2019, Vote Solar witness Barnes was also excused from the hearing and his pre-filed verified testimony was entered into the record without the witness being required to appear at the hearing. Sierra Club witness Hausman was also excused from the hearing on April 15, 2019, and his pre-filed verified testimony was also entered into the record without the witness being required to appear at the hearing. On April 16, 2019, ORS witnesses Schellinger and Sandonato were also excused from the hearing and their pre-filed verified testimony was entered into the record without the witnesses being required to appear in person at the hearing. In accordance with the Prepaid Stipulation, ORS did not present the testimony of ORS witness Johnson.

On April 15, 2019, during the hearing, counsel for DE Carolinas notified the Commission that the Company and the ORS had come to an agreement regarding the recovery of certain expenses the ORS had deemed non-allowable (the "Non-allowables Stipulation") and that the

Company and ORS further agreed that it is appropriate to resolve some of the conceptual issues around non-allowables in a separate administrative docket to provide clarity going forward.[4] In addition, on April 15, 2019, upon consultation with the ORS, the Company agreed to withdraw the supplemental testimony of witness Kerin.

On April 17, 2019, the Company and ORS entered into another Stipulation (the "ORS Stipulation") which was entered into the record as Hearing Ex. 73, regarding Accounting Adjustment No. 15 (End-of-Life Nuclear Reserve), Adjustment No. 21 (Adjustment to Non-Labor O&M), Adjustment No. 22 (Normalization of Storm Costs), Adjustment No. 25 (Rate Case Expenses), Adjustment No. 28 (Credit Card Fees), and Accounting Adjustment No. 39 (Nuclear Materials and Supplies) which are discussed further herein.

The Commission conducted an evidentiary hearing on this matter from April 11, 2019, through April 17, 2019, in the hearing room of the Commission with the Honorable Comer H. Randall presiding.

DE Progress witnesses Ghartey-Tagoe, Bateman, Coppola, Henderson, Hunsicker, Quick, Metzler, Panizza, Kerin, Wright, Hager, Hevert, Schneider, Sullivan, Turner and Wheeler; ORS witnesses Hamm, Johnson, Major, Morgan, Parcell, Payne, Seaman-Huynh, Ruoff, and Wittliff; SC NAACP et. al witness Wallach, Wal-Mart witness Chriss, and SCEUC witness O'Donnell appeared, gave summaries of their testimonies, and answered questions from counsel and the Commission.

On April 11, 2019, SC NAACP et. al witness Wallach testified in opposition to the Company's use of the minimum system method in allocating distribution-related costs as customer

[4] Tr. Vol. 5-1, p. 817-819.

related and the Company's request to increase its Basic Facilities Charge ("BFC") from a rate design perspective. DE Progress witnesses Bateman and Ghartey-Tagoe testified as the Company's first panel of witnesses. Witness Ghartey-Tagoe provided an overview of the reasons for the Company's request for an increase in electric rates and charges. Witness Bateman explained the Company's pro-forma accounting adjustments and revenue requirements for the test period in this case, the twelve months ending December 31, 2017 (the "Test Period"). Next, DE Progress presented its second panel of witnesses, Hunsicker, Quick and Schneider. Witness Hunsicker testified regarding the Company's Customer Connect program currently being deployed to replace its current customer information system ("CIS"). Witness Quick's testimony responded to ORS witness Major's recommendation to not include the Company's growth projections in the Company's proposed adjustment for credit, debit and Automated Clearing House ("ACH") payment (collectively, "credit card") expenses; and SC NAACP et al. witness Howat's request that the Company publicly file with the Commission monthly billing, payment, arrearage and disconnection data regarding general residential and low-income customer accounts. Witness Schneider testified regarding the deployment of the Company's AMI program.

The Commission reconvened on April 12, 2019, and continued to hear testimony from the Hunsicker, Quick and Schneider panel. Next, Company witness Panizza testified concerning the new 2017 Tax Cuts and Jobs Act impact to the Company and the proposed Excess Deferred Income Tax ("EDIT") rider. Next, the Company presented its third panel of witnesses, Henderson and Turner. Witness Henderson discussed the Company's nuclear generation fleet, capital and operating and maintenance ("O&M") expense, and operations performance, as well as the Company's request to begin collecting a reserve for nuclear End-of-Life ("EOL") costs. Witness Turner described the Company's new generation assets and other capital additions since the

Company's last general rate case in 2016 and operational performance of DE Progress' fossil, hydroelectric, and solar portfolio during the Test Period. Next, the Commission heard testimony from Company witness Metzler, who testified regarding the Company's employee incentive compensation program and why the Company believes it is appropriate to recover those costs from customers, as well as the appropriateness of certain expenses being included in rates. The Company presented its fourth panel of witnesses, Hager and Wheeler. Witness Hager testified regarding the Company's cost of service study and change in methodology to use the minimum system method and witness Wheeler testified regarding the Company's rate design and request to increase the BFC.

The Commission reconvened on April 15, 2019, with testimony from ORS witness Parcell who testified regarding the appropriate ROE based on his analyses, the Company's capital structure and his recommended ROE for the Company. DE Progress presented its fifth panel of witnesses Wright and Kerin. Witness Wright testified that the Company's practices around coal ash management were reasonable and prudent. Company witness Kerin testified regarding the Company's coal ash expenditures. Next, Company witness Coppola testified concerning litigation and other costs related to a contract the Company executed with CertainTEED Gypsum, NC, Inc., ("CertainTEED"). The Company presented its sixth panel of witnesses, Hevert and Sullivan. Witness Sullivan addressed the Company's financial objectives, capital structure, cost of capital, and cost of debt. Company witness Hevert presented his independent analysis of a fair ROE, which would allow DE Progress to attract capital on reasonable terms and maintain financial strength. Next, Walmart witness Chriss testified regarding his concerns with the amount of the Company's requested revenue requirement and proposed ROE. Next, SCEUC witness O'Donnell testified that the Commission should disallow a significant portion of the Company's request to recover its coal ash expense.

The Commission reconvened on April 16, 2019, with the testimony of ORS witness Ruoff. Witness Ruoff addressed the impact to customers if the Commission adopted the Company's positions outlined in its rebuttal testimony and testified that the Company's request for recovery was in excess of reasonable levels necessary to support safe, reliable and high-quality utility service. Next, ORS presented its first panel of witnesses, Seaman-Huynh and Wittliff. Witness Seaman-Huynh addressed the Company's cost of service study, depreciation study, rate design, revenue verification, and revenue requirement distribution and witness Wittliff testified regarding the Company's coal ash expense request and his recommended disallowances for certain coal ash expenses. Next, ORS presented it second panel of witnesses, Major and Payne. Witness Major explained the findings and recommendations as reflected in the ORS Audit Exhibits resulting from ORS' examination of DE Progress' Application and supporting books and records. Witness Payne offered recommendations for the treatment of the Company's requests for recovery of accounting deferrals.

The hearing reconvened on April 17, 2019. ORS presented its third panel of witnesses consisting of witnesses Morgan and Hamm. Witness Morgan testified regarding the Company's request to recover costs for the nuclear EOL reserve, ORS' proposed adjustment to the Company's nuclear materials and supplies inventory, the Company's request to recover CertainTEED litigation costs, the appropriate amortization period for the Company's deferred AMI balance, and the storm cost normalization.

As requested by the Commission, the Company entered late-filed Hearing Exhibit 41 provided on April 30, 2019, regarding accounting of the revenue stream from the reuse of coal ash byproducts.

II. GUIDING LEGAL PRINCIPLES

It bears noting the legal standards applicable to rate applications in South Carolina. The overarching legal standard that must be met by all electric utility rates approved by this Commission is found in S.C. Code Ann. § 58-27-810. That statute provides: "Every rate demanded or received by any electrical utility . . . shall be just and reasonable." This "just and reasonable" standard incorporates the rule that unjust or insufficient rates constitute an unconstitutional taking of private property for public use without just compensation in violation of the Takings Clauses of the United States and South Carolina Constitutions. U.S. Const. amends. V, XIV; S.C. Const. art. I, § 13(A); *see also Duquesne Light Co. v. Barasch*, 488 U.S. 299, 308 (1989) ("If the rate does not afford sufficient compensation, the State has taken the use of utility property without paying just compensation and so violated the Fifth and Fourteenth Amendments."). As related to these matters, the South Carolina Supreme Court has reasoned as follows: "the fixing of 'just and reasonable' rates involves the balancing of the investor and the consumer interests. . . . [T]he investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. *Southern Bell Tel. & Tel. Co. v. Pub. Serv. Comm'n*, 270 S.C. 590, 596-97 (1978) ("*Southern Bell*") (quoting *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 602-03 (1944) ("*Hope*").

These legal standards have been consistently employed by the Commission and the South Carolina courts and reflect the fact that utility customers have a direct interest, not only in low rates today, but also in the financial soundness of the utilities that serve them going forward. This is especially true for electric utility customers because of the universal and immediate importance of the electric utility service to the public and the capital investment that a utility must be able to make month-by-month to provide the quality of service that customers expect and depend on. As the U.S. Supreme Court stated in *Hope*:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

320 U.S. at 603 (citations omitted). This principle is often supplemented with language from *Bluefield*, where the U.S. Supreme Court held that:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

Bluefield Waterworks & Imp. Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679, 692-93 (1923) ("*Bluefield*") (citations omitted).[5] Indeed, long-standing precedent entitles utilities to rates that are sufficient "to yield a reasonable return on the value of the property used by a utility company to furnish its service to the public." *See Potomac Elec. Power Co. v. Pub. Serv. Comm'n*, 380 A.2d 126, 131 (1977) (citing *Fed. Power Comm'n v. Natural Gas Pipeline Co.*, 315 U.S. 575, 585-86 (1942); *McCardle v. Indianapolis Water Co.*, 272 U.S. 400, 408 (1926); *Bluefield*, 262 U.S. at 690)). Further, a utility is entitled to an opportunity to earn a reasonable return on "the value of that which it employs for the public convenience." *Bluefield*, 262 U.S. at 690 (quoting *Smyth v. Ames*, 169 U.S. 467, 547 (1898)). Rates that are not sufficient to yield a reasonable return on the value of that which

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[5] Together, the *Hope* and *Bluefield* cases provide "the basic principles of utility rate regulation" in South Carolina. *Southern Bell*, 270 S.C. at 595, 244 S.E.2d at 281; *Patton v. S.C. Pub. Serv. Comm'n,* 280 S.C. 288, 291, 312 S.E.2d 257, 259 (1984).

is employed for the public convenience "are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment." *Id.*

This Commission must exercise its dual responsibility of permitting utilities an opportunity to earn a reasonable return on the property it has devoted to serving the public, on the one hand, and protecting customers from rates that are so excessive as to be unjust or unreasonable, on the other, by "(a) Not depriving investors of the opportunity to earn reasonable returns on the funds devoted to such use as that would constitute a taking of private property without just compensation[, and] (b) Not permitting rates which are excessive." *Southern Bell*, 270 S.C. at 605. Ultimately, this balancing act takes place within the context of a utility setting forth proposed rates—pursuant to Title 58, Chapter 27, Article 7 of the S.C. Code of Laws—for the exclusive purpose of the utility receiving revenue sufficient to yield a reasonable return.

Practically, although the burden of proof in showing the reasonableness of a utility's costs that underlie its request to adjust rates ultimately rests with the utility, the S.C. Supreme Court has concluded that the utility is entitled to a presumption that its expenses are reasonable and were incurred in good faith. *Hamm v. S.C. Pub. Serv. Comm'n*, 309 S.C. 282, 422 S.E.2d 110 (1992) (internal citations omitted). Other parties are therefore required to produce evidence that overcomes both this presumption and any evidence the utility has proffered that further substantiates its position. *See Utils. Servs. of S.C., Inc. v. S.C. Office of Regulatory Staff*, 392 S.C. 96, 110, 708 S.E.2d 755, 762–63 (2011) ("Utility is correct that it was entitled to a presumption that its expenditures were reasonable and incurred in good faith . . . . [I]f an investigation initiated by ORS or by the PSC yields evidence that overcomes the presumption of reasonableness, a utility must further substantiate its claimed expenditures."). Ultimately, therefore, in the absence of sufficient countervailing evidence, the Commission must conclude that the utility's expenses are reasonable and were incurred in good faith. Finally, this Commission "has the power to independently determine whether an applicant has met its burden of proof," and the Commission is not bound by ORS' determination. *Util. Serv. of S.C., Inc. v. S.C. Office of Regulatory Staff*, 392 S.C. 96, 106 (2011).

Another long-standing regulatory standard applied by this Commission in setting rates is the application of a test year. As routinely recited by this Commission: "The test year is established to provide a basis for making *the most accurate forecast of the utility's rate base, revenues, and expenses in the near future when the prescribed rates are in effect*. The historical test year may be used as long as adjustments are made for any known and measurable out-of-period changes in expenses, revenues, and investments." *See* Order No. 2018-445, Docket No. 2016-384-S (2018) (citing *Porter v. S.C. Pub. Serv. Comm'n*, 328 S.C. 222, 493 S.E.2d 92 (1997)) (emphasis added); Order No. 2018-369, Docket No. 2017-28-S (2018); Order No. 2017-80, Docket No. 2016-29-WS (2017). The object of using test year figures is to reflect typical conditions. Where an unusual situation indicates that the test year figures are atypical, the Commission should adjust the test year data. *Parker v. S.C. Pub. Serv. Comm'n*, 280 S.C. 310, 312, 313 S.E.2d 290, 292 (1984). Indeed, the Commission must make adjustments for known and measurable changes in expenses, revenues, and investments so that the resulting rates will accurately and truly reflect the actual rate base, net operating income, and cost of capital. *Southern Bell*, 270 S.C. at 602–03, 244 S.E.2d at 284–85. Such adjustments are within the discretion of the Commission and, although they must be known and measurable within a degree of reasonable certainty, absolute precision is not required. *Hamm*, 309 S.C. at 291, 422 S.E.2d at 115 (citing *Michaelson v. New England Tel. & Tel. Co.*, 121 R.I. 722, 404 A.2d 799 (1979)); *Porter*, 328 S.C. at 230. Therefore, the test of whether known and measurable should apply is not whether a forecast or estimate is used, but if that forecast or estimate is shown to have a reasonable certainty of being accurate. The words "forecast" or "estimate" are not enough to render a cost "not" known and measurable—a more specific, factual inquiry should be made to see if the particular cost or revenue item in question is reasonably certain.

The purpose of this regulatory scheme of using a test year and making adjustments based on atypical conditions is to permit sufficient and accurate cost recovery as the expenses are incurred by the utility in real-time. In other words, the purpose of this ratemaking exercise of using a test year and making appropriate adjustments is to match—as closely as possible—the utility's revenue to the costs it will incur after the rates are implemented. *See Southern Bell*, 270 S.C. at 602, 244 S.E.2d at 284 ("[W]e believe that the Commission should make any adjustments for known and measurable changes in expenses, revenues and investments occurring after the test year, in order that the resulting rates will reflect the actual rate base, net operating income, and cost of capital."). In that regulatory context, there is no need to consider the time value of money or the carrying costs of debt because the utility's revenue matches its expenses as they are incurred.

The Commission's Findings of Facts and Legal Conclusions reflect these standards.

III. AREAS OF DISPUTE

The Company's case is only its second contested rate case since 1988. While many areas are not in dispute or have been stipulated, other areas are contested. Specifically, there are thirteen accounting and pro forma adjustments proposed by the Company that are not contested, and five additional adjustments recommended by the ORS that the Company has agreed to accept as discussed further herein.

The Company entered into a number of stipulated agreements with Parties in this case including the Prepaid Stipulation, Nucor Stipulation, Non-Allowables Stipulation, and ORS

Stipulation (collectively, the "2018 DE Progress Rate Case Stipulations"). Per the terms of the ORS Stipulation, the ORS and Company also reached agreement regarding Company accounting Adjustment No. 15 (End-of-Life Nuclear Reserve), Company accounting Adjustment No. 20 (Normalize for Storm Costs), Company accounting Adjustment No. 21 (Adjustment to Non-Labor O&M), Company accounting Adjustment No. 25 (Rate Case Expenses) (whether the unamortized balance should be included in rate base remains contested), Adjustment No. 28 (Credit Card Fees), and ORS accounting Adjustment No. 39 (Nuclear Materials and Supplies) as discussed further herein. Other accounting adjustments remain contested and are addressed herein. The ORS and Company also reached the Non-Allowables Stipulation regarding recovery of some categories and expenses the ORS deemed non-allowable. Specifically, the ORS agreed to no longer contest the costs related to the Lineman's Rodeo, allocations not 100% related to South Carolina, accruals/timing differences and split service/safety awards, and the Company agreed to withdraw its requests to recover costs related to other employee recognition and reward and certain other miscellaneous expenses.[6] The Company and the ORS also agreed to address the Company's proposed GIP and Prepaid Pilot in separate dockets per the terms of the GIP Stipulation and Prepaid Stipulation, respectively.

In addition, no party in this proceeding opposed the Company's request to revise its customer rates to reflect the revised depreciation rates; the Company's proposed base fuel and fuel-related factor, or the prudency of the Company's investments in nuclear, hydro, solar, or its transmission and distribution system. Through the Nucor Stipulation, the Company and Nucor also reached agreement on the manner in which the Federal Tax Cuts and Jobs Act of 2017 ("Tax

[6] Tr. Vol. 5-1, p. 817-819.

Act") should be addressed in this case, which no other party disputed. The Parties agreed to address the Company's proposed GIP and request to approve its Prepaid Pilot in separate dockets. Also undisputed is the Company adjustment to remove 50% of the compensation of the four Duke Energy executives with the highest level of compensation allocated to DE Progress in the Test Period, though the mechanics of the adjustments are treated differently by the ORS (see Adjustments #22 and #29 discussed further herein).

The Company initially requested to increase the amount of the BFC to $29 a month but later agreed in a letter dated March 26, 2019, with the numeric value stated by the ORS, to increase the BFC to $11.78 for residential customers, $12.34 for SGS customers, and $11.31 for SGS Constant Load customers, and to put the remaining revenue requirement ultimately determined by the Commission in the variable component of the Company's base rates. The Company suggested updating the cost of long-term debt in this case and the ORS agreed with the Company's proposal in surrebuttal. The Company's requests to recover deferred costs related to its AMI and Customer Connect deployments are also uncontested except with respect to the ORS' recommendation concerning recovery of a return on the deferred costs.

The other contested areas in this case include: (1) the appropriate ROE that the Company should be allowed in this case; (2) the appropriate recovery of the Company's deferred costs including the appropriate amortization period and whether the Company should be permitted to earn a return on its deferred costs both during the deferral period and the amortization period; (3) the Company's use of the Minimum System Method to allocate distribution costs as customer-related costs in the Company's cost of service studies, and the separate issue of establishing a BFC based on other methodology, including gradualism; (4) whether the Company's proposed adjustment to include Customer Connect projected two-year average O&M expense is sufficiently known and measurable to appropriately include in rates; (5) whether the Company should be allowed to recover certain CertainTEED litigation expenses and ongoing payment obligation costs; (6) whether certain costs the ORS has characterized as "non-allowable" (such as expenses related to state and local chambers of commerce and other community organization membership dues,) should be included in rates; (7) whether a portion of the Company's incentive compensation relating to shareholder and earnings metrics should be disallowed; (8) whether the Company should be required to submit monthly billing, collection and disconnect data on residential and low-income customers; (9) whether the Company should be permitted to recover its $100 million investment in the dry bottom ash system at the Roxboro Station and whether the Company should be required to perform comprehensive economic analyses before making investments needed to continue to operate its coal plants; (10) treatment of the Company's coal ash expenses, including whether costs imposed as a result of the Coal Ash Management Act ("CAMA") should be collected from South Carolina customers; (11) whether ORS' criticism of the Company's response to data requests from the ORS is justified and sufficient to overcome the presumption of reasonableness related to the requested recovery of certain legal expenses related to coal ash litigation, including litigation to pursue insurance monies to help offset coal ash compliance costs for customers and (12) whether the Company has provided appropriate notice of the proposed rate increase to meet the due process requirements of S.C. Const., Art. 1, § 22.

IV. FINDINGS OF FACT

Based upon the Application, the testimony, and exhibits received into evidence at the hearing and the entire record of these proceedings, the Commission makes the following findings of fact:

A. Jurisdiction

1. DE Progress is a limited liability company duly organized and existing under the laws of the State of North Carolina. It is a public utility under the laws of the State of South Carolina and is subject to the jurisdiction of this Commission pursuant to S.C. Code Ann. § 58-3-140(A). The Company is engaged in the business of generating, transmitting, distributing and selling electric power to the public in the northeastern portion of South Carolina, a substantial portion of the coastal plain of North Carolina extending from the Piedmont to the Atlantic coast and between the Pamlico River and the South Carolina border, the lower Piedmont section of North Carolina and area in western North Carolina in and around the City of Asheville. DE Progress, with its offices and principal places of business in Raleigh, North Carolina, is a wholly-owned subsidiary of Duke Energy, with its offices and principal place of business in Charlotte, North Carolina.

2. The Commission has jurisdiction over the rates and charges, rate schedules, classifications, and practices of public utilities operating in South Carolina, including DE Progress, as generally provided in S.C. Code Ann. §§ 58-27-10, *et seq*.

3. DE Progress is lawfully before the Commission based upon its Application for a general increase in its retail rates pursuant to S.C. Code Ann. §§ 58-27-820, 5827-870, and 26 S.C. Code Ann. Regs. 103-303 and 103-823.

4. The appropriate test period for use in this proceeding is the 12 months ended December 31, 2017, adjusted for certain known changes in revenue, expenses, and rate base.

B. DE Progress' Request For a Rate Increase

5. DE Progress, by its Application and initial direct testimony and exhibits, originally sought a base rate increase of $68,668,000[7] in its annual electric sales revenues from its South Carolina retail electric operations, including a rate of return on common equity ("ROE") of 10.5% and a capital structure consisting of 47% debt and 53% equity.

6. DE Progress submitted evidence in this case with respect to revenue, expenses, and rate base using a test period consisting of the 12 months ended December 31, 2017, adjusted for certain known changes in revenue, expenses, and rate base.

7. DE Progress, by its rebuttal testimony and exhibits, revised its requested base revenue requirement to $68,501,000[8] to incorporate the Company's adjustments filed in its supplemental filing and the Company's rebuttal position.

8. The increased capital costs reflected in the Company's request for a rate increase were reasonably and prudently incurred. The Commission finds and concludes that the capital investments by the Company provide significant benefits to all of its customers. These capital investments are necessary for DE Progress to meet its obligation to provide safe, adequate, and reliable electric service. There is no credible and substantial evidence disputing the prudency, reasonableness, or necessity of these costs.

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[7] The additional base revenue requested in the Application was $68,668,000. (Hearing Ex. 14 (Bateman Ex. 1, p. 2.) As described below, in the Application, the Company has also proposed an EDIT Rider, which was originally calculated to decrease year 1 revenues by $10,008,000, for a net increase of $58,660,000. (*See* Hearing Ex. 14 (Bateman Ex. 3, p.2).)

[8] As shown in Bateman Rebuttal Exhibit 1, the additional base revenue requested by the Company in this case has been adjusted to $68,501,000. (Hearing Ex. 17 (Bateman Rebuttal Ex. 1, p. 2).) The Company also adjusted its proposed EDIT Rider decrement to year 1 revenues to $12,802,000, for a net increase of $55,699,000. (*See* Hearing Ex. 16 (Bateman Revised Second Supplemental Ex. 3, p. 2).) The Company is requesting approval of its revised base revenue requirement as adjusted subject to the terms of the ORS and Non-allowables Stipulations approved herein.

C. Return on Equity, Cost of Debt, and Capital Structure

9. Based on the record in this proceeding, the Commission finds 10.5% to be a reasonable ROE for DE Progress for purposes of this general rate case.

10. Based on the record in this proceeding, the Commission finds 53% equity and 47% debt to be a reasonable capital structure for DE Progress for purposes of this general rate case.

11. Based on the record in this proceeding, the Commission finds 4.16% to be a reasonable cost of debt for purposes of this general rate case.

12. The Commission finds that DE Progress, through sound management, shall have the opportunity to earn an overall rate of return of 7.52%. This overall rate of return is derived from applying an embedded cost of debt of 4.16% and an ROE of 10.5% to a capital structure consisting of 47% long-term debt and 53% equity. The Commission finds and concludes that evidence in this case supports DE Progress' overall rate of return, cost of debt, ROE, and capital structure.

D. Accounting and Pro Forma Adjustments

13. The Company made certain accounting and pro forma adjustments, some of which the Company and the ORS agreed upon and some of which are in dispute, as further described below. The Commission finds and concludes that the accounting adjustments outlined in Hearing Ex. 17 (Bateman Rebuttal Exhibit 1), as modified per the terms of the ORS and Non-allowables Stipulation, are just and reasonable to all Parties in light of all the evidence presented.

End of Life Nuclear Costs

14. DE Progress requested an accounting order for approval to establish a reserve for end-of-life nuclear costs that are not captured in a decommissioning study. The Company proposes to create a reserve to start accruing for these end-of-life expenses to create a better matching of

cost and benefit for ratemaking purposes. The ORS agreed to the Company's proposed adjustment per the terms of the ORS Stipulation. The annual accrual amount will be determined by dividing the projected inventory balance at the end of each unit's life by the number of years remaining in the unit's life and summing this result for the Company's three nuclear plants. The annual accrual amount can be reviewed and adjusted, if needed, in each future general rate case before the end of each plant's life.

15. The Company also proposes to create a reserve to start accruing for the expenses related to a portion of the last core of nuclear fuel in the reactor at the end-of-life of its nuclear generating plants to create a better matching of cost and benefit for ratemaking purposes. The ORS agreed to the Company's proposed adjustment per the terms of the ORS Stipulation. The annual accrual amount will be determined by dividing the projected remaining value of the last core of nuclear fuel at the end of each unit's life by the number of years remaining in the unit's life and summing this result for the Company's three nuclear plants. The annual accrual amount can be reviewed and adjusted, if needed, in each future general rate case before the end of each plant's life. The reserves, once they are created, will be included as an offset to rate base in the cost of service.

16. The Commission finds that the Company's request to adjust depreciation and amortization expenses to establish a reserve for these end-of-life nuclear expenses as agreed to in the ORS Stipulation is just and reasonable in light of the evidence presented.

Storm Costs

17. DE Progress initially proposed a proforma adjustment to normalize storm restoration costs to the average level of costs the Company experienced over the past ten years.

Per the ORS Stipulation, the ORS and the Company agree to instead use a five-year average removing the highest and lowest year costs from the calculation.

18. The Company also proposed to adjust each storm cost year included in the average to be comparable to the test year on a historic inflation adjusted basis but subsequently agreed to remove the inflation adjustment per the terms of the ORS Stipulation. The Commission finds that the Company's request to normalize its storms costs as adjusted per the terms of the ORS Stipulation is just and reasonable in light of the evidence presented.

O&M Non-Labor Expenses

19. The Company initially proposed to adjust O&M Non-Labor Expenses to reflect the change in costs that occurred during the Test Period. Pursuant to the terms of the ORS Stipulation, the Company subsequently agreed to the ORS adjustment to remove the inflation adjustment. The Company's agreement to remove the inflation adjustment to O&M non-labor expenses as agreed to per the terms of the ORS Stipulation is just and reasonable in light of the evidence presented.

Rate Case Costs

20. The Company proposed to amortize the incremental rate case costs incurred for this docket over a five-year period and to recover a net of tax return on the unamortized balance. Per the terms of the ORS Stipulation, the parties subsequently agreed to the calculation of rate case expenses reflected in the ORS' Adjustment #25 (actual rate case expenses received and verified by ORS through December 31, 2018). The Commission finds and concludes that, per the terms of the ORS Stipulation, the rate case expenses the Company has incurred in this docket and that have been verified by the ORS through December 31, 2018 are reasonable and prudently incurred. The Commission further finds and concludes that the Company's request to recover its deferred rate

case expenses, including the after-tax return on the unamortized balance through inclusion in rate base, is just and reasonable to all Parties in light of the evidence presented.

21. Subject to the terms of the ORS Stipulation, the parties agreed that the Company will continue to defer rate case expenses incurred after December 31, 2018 and will continue to send invoice documentation to ORS to audit. The Commission finds and concludes that the Company's request to continue to defer its rate case expenses incurred or verified after December 31, 2018 subject to the terms of the ORS Stipulation, is just and reasonable to all Parties in light of the evidence presented.

Credit Card Fees

22. The Company proposed to allow residential customers to pay their electric bills using credit cards, debit cards, and ACH payments without being charged a convenience fee. Instead, the Company proposed to recover the costs of credit card expenses through the Company's cost of service. The Company initially included an adjustment to cost of service to reflect a reasonable level of growth associated with the projected increase in usage of credit cards resulting from removal of the convenience fee. Subsequently, per the terms of the ORS Stipulation, the Company and ORS agreed to instead use the 2018 actual transactions of 449,456 times the $1.50 fee for a total adjustment of $674,000.

23. The Company's proposal to recover the costs of credit card fee expenses through the Company's cost of service pursuant to the terms of the ORS Stipulation is just and reasonable in light of the evidence presented.

Nuclear Materials & Supplies Inventory

24. The ORS proposed to adjust materials and supplies inventory to nuclear materials and supplies inventory at the Company's nuclear stations that have remained in a hold status for a

period greater than four years. Per the terms of the ORS Stipulation, the Company and ORS agreed to adjust nuclear materials and supplies inventory by ($599,000) to remove nuclear materials and supplies inventory at the Company's nuclear plants that have remained in a hold status for a period greater than four years. The Commission finds that the adjustment to nuclear material and supplies inventory agreed to by the Company and ORS under the ORS Stipulation is just and reasonable in light of the evidence presented.

Request for Accounting Order to Defer Costs Related to Asheville Retirement

25. The Company requested an accounting order for approval to establish a regulatory asset related to the retirement of the Company's Asheville coal plant. The Asheville plant was originally expected to be fully depreciated by its expected retirement date in 2020. However, to mitigate the rate impact to customers, the Company's depreciation consultant adjusted its depreciation rates to reflect recovery of the remaining net book value over a ten-year period. Because the net book value of the plant will not be fully recovered at the time of retirement, the Company requests to include in rate base a regulatory asset at the time of the Asheville plant's retirement for the remaining net book value and the ability to continue amortizing the costs over the remaining portion of the ten-year period at that time. The Company also requests permission to defer to this regulatory asset any costs related to obsolete inventory, net of salvage, at the time of retirement. The Commission finds that the Company's request for an accounting order is just and reasonable in light of the evidence presented and is approved.

Harris COLA, Fukushima/Cybersecurity, GridSouth, and 2014 Storms

26. DE Progress has deferred into regulatory asset accounts costs incurred from the suspension of its Harris Units 2 and 3 Combined License Application ("Harris COLA") review with the Nuclear Regulatory Commission ("NRC"), costs related to compliance with the NRC

requirements in response to events at the Fukushima Daiichi Nuclear Power Station ("Fukushima") in 2011 and NRC requirements related to cybersecurity, GridSouth Regional Transmission Organization ("RTO") costs. The Commission approved the Company's request to grant an extension of the deferrals associated with the 2014 storms in Order No. 2019-126 in Docket No. 2019-26-E, thus no further action is required by the Commission concerning those deferrals in this case. DE Progress is seeking recovery of the Harris COLA over a five-year period without inclusion of the unamortized balance in rate base and is also requesting recovery of the Fukushima/cybersecurity and GridSouth deferred costs over a five-year period including a net of tax return on the unamortized balance of the regulatory assets through inclusion in rate base. The Commission finds and concludes that the Company's request to recover the regulatory assets for the Harris COLA is appropriate and that the Company's request to recover the regulatory assets for the Fukushima/Cybersecurity and GridSouth deferred costs over a five-year period, including the after-tax return on the unamortized balance, is just and reasonable to all Parties in light of the evidence presented.

AMI

27. The Commission finds and concludes that DE Progress' AMI project will provide significant benefits to the Company's customers and that the test year costs for the AMI project are reasonable and prudently incurred.

28. The Company has deferred into a regulatory asset account the incremental O&M expense and depreciation expense incurred once the AMI meters were installed, as well as the associated carrying costs on the investments and the deferred costs at its weighted average cost of capital. The Company is seeking recovery of the deferred costs over a three-year period including a net of tax return on the unamortized balance of the regulatory asset through inclusion in rate

base. The Commission finds and concludes that the Company's request to recover the regulatory asset over a three-year period, including the after-tax return on the unamortized balance, is just and reasonable in light of the evidence presented.

29. The Company is also requesting permission to defer the incremental O&M and depreciation expense associated with ongoing AMI deployment, specifically related to meters placed in service after December 31, 2018, including the carrying charge on the investment and on the deferred costs at the weighted average cost of capital approved in this case. The Commission finds and concludes that the Company's request to establish a regulatory asset/liability account associated with the costs of its ongoing AMI deployment is just and reasonable in light of the evidence presented.

Grid Deferral

30. The Company has deferred costs incurred in connection with grid reliability, resiliency, and modernization work in a regulatory asset account until the time the costs are reflected in new rates from this proceeding. The Company is seeking recovery of the deferred costs over a two-year period, including a net of tax return on the unamortized balance of the regulatory asset. The Commission finds and concludes that the Company's request to recover the regulatory asset over a two-year period, including the after-tax return on the unamortized balance through inclusion in rate base, is just and reasonable in light of the evidence presented.

Employee Compensation

31. The Company proposed to remove 50 percent of the compensation of the four Duke Energy executives with the highest level of compensation allocated to DE Progress in the Test Period. The ORS agreed to this adjustment, and it was not contested by any Party. The Commission finds this adjustment is just and reasonable in light of the evidence presented.

32. The Company adjusted O&M labor expenses – wages, salaries, and related employee benefit costs – to reflect annual levels of costs as of July 1, 2018, as well as changes in related payroll taxes. The ORS recommends updating the salary allocator for DE Progress to the same date as the O&M labor expense – i.e., July 1, 2018. The Company does not oppose this recommendation. The Commission finds this adjustment is just and reasonable in light of the evidence presented.

33. The ORS has proposed to remove 50% of the Company's long-term incentive ("LTI") program costs and 50% of the Company's short-term incentive ("STI") costs incurred as of July 1, 2018. The Commission finds and concludes that the proposed removal of a portion of the Company's LTI and STI costs is inappropriate, and therefore is rejected by the Commission.

Customer Connect

34. The Company is seeking recovery of its deferred costs associated with implementing its new billing and CIS (known as "Customer Connect"), which will replace the Company's current CIS system. Specifically, the Company is seeking recovery of the deferred costs over a three-year period, including a net of tax return on the unamortized balance of the regulatory asset through inclusion in rate base.

35. The Commission finds and concludes that the deferred costs incurred for the Customer Connect project are reasonable and prudent and shall be amortized over a three-year period, as requested by the Company, and shall include a net of tax return on the unamortized balance of the regulatory asset through inclusion in rate base.

36. The Company has proposed to increase O&M expense by $1,227,000 to recover O&M expenses associated with the ongoing deployment of Customer Connect. The Company is required to report to the Commission the actual Customer Connect O&M costs incurred on an

annual basis. The Commission finds and concludes that the annual Customer Connect expenses the Company seeks to recover in this case are known and measurable and shall be recovered by the Company as requested.

Non-Allowables

37. The ORS initially recommended removing O&M expense from the Test Period for certain costs, including: (1) employee incentives, service and safety awards, and costs that recognize and reward the Company's employees; (2) costs relating to the Lineman's Rodeo; (3) organization dues, such as membership dues for local South Carolina Chambers of Commerce and other local South Carolina civic organizations; (4) costs that are not 100 percent related to South Carolina, such as registration fees paid to the North Carolina Department of Motor Vehicles for transmission vehicles that are system assets; (5) costs relating to timing differences, such as transactions where the invoice due date and payment date were in different years; and (6) coal ash litigation expenses. During the hearing as part of the Non-allowables Stipulation, the Company agreed that it would withdraw its request to recover $39,532 in costs related to employee recognition and reward and $112,736 in other miscellaneous costs. The ORS agreed that it would no longer contest $26,231 in costs related to the Lineman's Rodeo, $4,066 in costs for allocations not 100% related to South Carolina, $12,366 related to accruals and timing differences and half of the $31,655 in costs for service/safety awards.[9] The Commission finds and concludes that the Non-Allowables Stipulation between the ORS and Company is just and reasonable, and the remaining costs disputed by the ORS are properly included in rates, and therefore rejects the ORS' recommendation to disallow those costs.

[9] Tr. Vol. 5-1, p. 817-819.

Adjustments Related to CertainTEED Agreement

38. DE Progress' decision to enter into, litigate, and settle upon the disputed CertainTEED Agreement resulted in a net benefit of $50 million dollars to ratepayers, and is directly related to the Company's provision of adequate electrical service, as the gypsum at issue in the contract was a byproduct of the Company's coal-fired electric generation. It is reasonable and appropriate for the Company to recover the total litigation expenses and payment obligations related to the Company's defense and settlement of the CertainTEED Agreement, including the Company's legal fees ($389,995 when combined with the coal ash legal fees) and payment obligations ($830,000).

Adjustments #32, 33, 40, 41

39. For Company Adjustment #32, (Synchronize Interest Expense with End of Period Rate Base), #33 (Adjust 1/8 O&M for Accounting and Pro Forma Adjustments), and ORS Adjustment #40 (Customer Growth), and ORS Adjustment #41 (Adjust Revenue, Taxes, and Customer Growth for Proposed Increase), the Company and the ORS agree on the concept of and the method used to calculate these adjustments. The ORS and Company amounts differ only due to the underlying adjustments of ORS and the Company and the recommended ROE. Because the Commission has found in favor of DE Progress on the underlying adjustments and ROE, the Commissions finds and concludes that the Company's Adjustments #32 and #33, the Company's adjustment for Customer Growth and for Revenue, Taxes and Customer Growth for Proposed Increase, once adjusted for the ORS and Non-Allowables Stipulations, are just and reasonable in light of the evidence presented in this proceeding.

E. Fuel Factors

40. The fuel cost factors utilized in the Company's initial November 8, 2019 filing were the Company's fuel cost factors as of July 1, 2018 approved in Docket No. 2018-1-E. These fuel factors were the most recently approved billing factors at the time the Company prepared its Application in this proceeding. Accordingly, the Company proposes to use the following base fuel factors by customer class (excluding gross receipts tax and regulatory fees):

- Residential 3.087 cents per kilowatt hour ("kWh")
- General Service-Non Demand 2.801 cents per kWh
- General Service - Demand 2.366 cents per kWh, 89 cents per kilowatt ("KW")10
- Lighting 2.366 cents per kWh

The Commission finds and concludes that the proposed base fuel and fuel-related factors are just and reasonable in light of all the evidence presented.

F. Cost of Service

41. The Company has proposed the Summer Coincident Peak ("SCP") methodology for cost allocation between jurisdictions and among customer classes in this case. The Commission finds and concludes that for purposes of this proceeding, the Company may continue to use the SCP methodology for allocation between jurisdictions and among customer classes and that the Company's cost of service methodology is just and reasonable to all Parties in light of all the evidence presented. The Commission also finds the Company's use of the Minimum System Method to allocate customer-related distribution costs is reasonable and appropriate for the

[10] The environmental Distributed Energy Resource Program ("DERP") avoided costs, and capacity-related components of fuel costs factors are billed on a cents per KW basis for General Service-Demand customers.

purposes of allocating costs to the respective rate classes, which is a separate and distinct issue as to whether Minimum System alone is appropriate for rate design.

G. Rate Design and Basic Facilities Charge

42. DE Progress proposes modification of certain rate schedules to reflect more accurately its cost of service. Except for the amount of the BFCs and the allocation of the revenue requirement to LGS-CUR-TOU rate schedule which are addressed below, the rate design proposed by Company witness Wheeler's revised tariffs in Exhibit C to the Application are just and reasonable in light of the evidence presented.

43. Per the terms of the Nucor Stipulation, the Company agreed that in determining the LGS-CUR-TOU rate schedule increase in this proceeding, the Company agrees to apply the final approved LGS class percentage revenue increase to the revenues for the LGS-CUR-TOU rate schedule. The Commission finds this allocation to be just and reasonable and approved per the terms of the Nucor Stipulation.

44. The Company proposes to modify its BFCs for various customer classes to better reflect the underlying cost of service. In its Application, the Company originally proposed an increase in the Residential Basic Facilities Charge from $9.06 to $29.00 per month.[11]

45. In a letter filed in this Docket on March 26, 2019, DE Progress notified the Commission and Parties that based upon the Company's review of the surrebuttal testimony of ORS witness Seaman-Huynh and testimony heard at the public hearings, the Company does not contest the BFC proposed by ORS in witness Seaman-Huynh's surrebuttal testimony as follows:

[11] The increase in the Basic Facilities Charge is not additive to the rate increase requested in this case. Rather, the Company proposes to collect fixed costs through the fixed monthly charge – i.e., the Basic Facilities Charge – based on the cost to serve instead of the variable, volumetric energy rate.

$11.78 for residential customers, $12.34 for SGS customers, and $11.31 for SGS Constant Load customers, and to put the remaining revenue requirement ultimately determined by the Commission in the variable component of the Company's base rates.

46. The numeric values for the BFCs as set forth in in the surrebuttal testimony of witness Seaman-Huynh and the Company's March 26, 2019 letter are just and reasonable and are therefore approved by the Commission.

H. Customer Notice

47. The notice provided of the Application in this proceeding meets the due process requirements of S.C. Const., Art. 1, § 22.

I. Customer Data

48. SC NAACP et al., recommended that DE Progress should be required to provide detailed monthly residential and low-income customer usage data by zip code in a format accessible to the public. Investor-owned utilities are already subject to certain quarterly reporting requirements regarding disconnections in Docket No. 2006-193-EG and it is not appropriate to unilaterally require DE Progress to provide a different level of detailed customer and billing data at this time. The parties and the Commission will know more about the availability of such data, and the cost of collecting and reporting it, once the Customer Connect Program is fully implemented. As a result, the Commission declines to adopt SC NAACP et al.'s proposal.

J. Depreciation

49. The Company's request to increase customer rates to reflect the revised depreciation rates, as adjusted, and filed by the Company as Doss Exhibit 3, part of composite Hearing Ex. 21, are just and reasonable and should be approved in this case.

K. EDIT Rider

50. The Company has proposed to implement flow back of excess deferred income taxes to customers through an EDIT Rider, as follows:

a. For Federal EDIT protected under Internal Revenue Service ("IRS") normalization rules, in accordance with those rules;

b. For Federal EDIT not protected by normalization rules, but related to property, plant and equipment, over a 20-year period;

c. For Federal EDIT not protected by normalization rules, but not related to property, plant and equipment, over a five-year period;

d. For deferred revenue, net of deferred balances related to the DERP, over a five-year period; and

e. For North Carolina EDIT, to refund the full remaining balance to customers in year 1 of the EDIT rider.

Pursuant to the Nucor Stipulation, the Company agreed to modify its proposed EDIT Rider as follows:

a. all deferred revenues from January 2018 through May 2019, related to the reduction in the federal tax rate, shall be returned to ratepayers over three years (instead of five years as originally proposed in the Application); and

b. the amount of DERP deferred balances to be offset under the Rider shall be reduced to $6 million (instead of $12.66 million as originally proposed in the Application).

51. The Company's proposed EDIT Rider, as modified per the terms of the Nucor Stipulation, is just and reasonable, and will result in rates that are just and reasonable, and should be implemented. The appropriate annual revenue requirement for the EDIT Rider is a decrement of $12,802,000 in year 1.

L. Environmental Compliance Costs

52. DE Progress has become subject to new legal requirements relating to its management of Coal Combustion Residuals ("CCRs"). These new legal requirements mandate the closure of the coal ash basins at all of the Company's coal-fired power plants and require certain modifications at

the Company's active and decommissioned coal-fired plants. Since its last rate case, DE Progress has incurred significant costs to comply with these new legal requirements.

53. In its original filing, the Company requested recovery of its deferred CCR compliance costs of approximately \$50.4 million over a five-year period, resulting in an increase to amortization expense of \$10,080,000. The \$50.4 million reflects the \$50.8 million related to South Carolina's allocation of the total system spend on ash basin closure cost subject to ARO accounting from July 2016 through December 2018 (adjusted for CAMA-specific costs, excess decommissioning regulatory liabilities and the return on the deferred costs), subtracted by the \$1.5 million from the balance to exclude the South Carolina retail portion of an amount the North Carolina Commission disallowed. In addition, the \$50.4 million consists of \$1.1 million related to deferred depreciation on Non-ARO investments and the return on these investments and the deferred costs. At the time of the filing, the deferred balance was partially based on projections through December 2018. In supplemental testimony, the Company updated the amount based on actuals and showed an updated annual amortization expense of \$9,297,000 in Hearing Ex. 17 (Bateman Rebuttal Exhibit 1, p. 3). The actual coal ash basin closure costs incurred by DE Progress are reasonable, prudent and used and useful in the provision of service to the Company's customers in South Carolina. DE Progress is entitled to recover these costs in rates. The five-year amortization period proposed by the Company is appropriate and reasonable, and should be approved, and the Company is entitled to earn a return on the unamortized balance, through inclusion in rate base.

54. The Company expects to continue to invest significant amounts related to coal ash compliance after the December 2018 cut-off in this case. However, instead of requesting recovery of an ongoing level of these costs in this rate case, DE Progress proposes that the Commission approve a continuation of the deferral, similar to what the Commission approved in Docket 2016-227-E, for

costs not included in this case. Specifically, the Company proposes deferral of environmental compliance spend related to ash basin closure beginning January 1, 2019, deferral of the depreciation and return on compliance investments related to continued plant operations placed in service on or after January 1, 2019, and a return on both deferred balances at the overall rate of return approved in this case. The Company's proposal to continue deferral of these ongoing costs is reasonable and appropriate and is approved.

M. Roxboro Plant Investment and Retirement Analyses for Coal-Fired Plants

55. Sierra Club witness Hausman recommends the Commission deny the Company's request to recover its $100 million investment in the dry bottom ash system at the Roxboro plant and require the Company to undertake retirement analyses regarding capital investments at its coal fired plants prior to seeking recovery for such investments. No other party contested the Company's investment. The Commission finds and concludes that the Company's current practices and analyses used to manage its fleet are reasonable and appropriate. The Company is not required to seek pre-approval of its capital improvements, but rather must justify its capital investments, including the prudency of its costs and the usefulness of its investments for customers, in rate cases. Accordingly, the Commission declines to disallow the $100 million investment in the Roxboro plant in the dry bottom ash system or mandate the performance of retirement analyses prior to the Company's decision to make capital improvements.

N. Prepaid Advantage Program

56. DE Progress is seeking approval of its Prepaid Pilot. The Company and ORS entered into the Prepaid Stipulation whereby the parties agreed that the Company's request regarding the Prepaid Pilot will be withdrawn and may be addressed in a separate docket. The Parties further agreed that provided the Company implements the Pilot in the same manner that DE Carolinas

implements its Prepaid Pilot program, the ORS will (a) not object to the Company's Prepaid Pilot and (b) not oppose the Company seeking expedited review of its Prepaid Pilot. The Commission approves the Prepaid Stipulation as a just and reasonable resolution of this issue.

O. Revenue Requirement

57. Based on the foregoing, the appropriate base revenue requirement is $68,501,000, after accounting and pro forma adjustments, as set forth in Hearing Ex. 17 (Bateman Rebuttal Exhibit 1), as adjusted subject to the ORS and Non-Allowables Stipulations approved in this case.[12]

58. The base non-fuel and base fuel revenues approved herein are just and reasonable to the customers of DE Progress to the Company, and to all Parties in this proceeding, and serve the public interest.

V. EVIDENCE AND CONCLUSIONS

EVIDENCE FOR FINDINGS AND CONCLUSIONS NOS. 1-4

The evidence supporting these findings and conclusions is contained in the verified Application of the Company, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

DE Progress is an electric utility subject to the jurisdiction of the Commission pursuant to S.C. Code Ann. Sections 58-3-140(A) (Supp. 2010). The test year is the period of time selected to evaluate the cost of providing service and the adequacy of existing rates. Essential to this method of evaluating rates is the establishment of a cut-off date to ensure some degree of finality in the rate making process. *Parker v. S.C. Pub. Serv. Comm'n*, 313 S.E. 2d 290, 291-92 (S.C.

[12] The base revenue increase does not include the impact of EDIT Rider year 1 reduction of ($12,802,000) as calculated in Hearing Ex. 16 (Bateman Revised Second Supplemental Exhibit 3, p 2).

1984). South Carolina uses a historic twelve-month test period. 26 S.C. Code Ann. Regs. 103-823(A)(3). The historic test year approach uses the most recent twelve-month period for which data is available at the time of filing a rate proceeding. A historic test year is based primarily upon the recorded results for the twelve-month period, although the Commission can recognize adjustments to these results that are designed to shape the recorded year into a "normal" representation of the period. The Commission finds the twelve months ending December 31, 2017, adjusted for certain known changes in revenue, expenses, and rate base, to be the reasonable period upon which to base its ratemaking determination.

These findings and conclusions are informational, procedural and jurisdictional in nature and are not contested by any of the Parties.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NOS. 5-8

The evidence supporting these findings and conclusions is contained in the Company's verified Application, the 2018 DE Progress Rate Case Stipulations, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

The Commission last approved the Company's general electric rates and tariffs in Order No. 2016-871 in Docket No. 2016-227-E, which allowed the Company a 10.10% ROE. The test period in that case was the twelve (12) months ended December 31, 2015, adjusted for known and measurable changes.

On November 8, 2018, DE Progress filed its Application and initial direct testimony and exhibits, seeking a net increase of approximately $59 million or 10.3 percent average increase in its annual electric sales revenues from its South Carolina retail electric operations. The additional base revenue requested in the Application was $68,668,000. As described below, in the Application, the Company has also proposed an EDIT Rider, which was originally calculated to decrease year 1 revenues by ($10,008,000), for a net increase of $58,660,000. The Company requested a 10.5 percent ROE.

On March 18, 2019, the Company filed rebuttal testimony and exhibits adjusting its proposed base revenue requirement to $68,501,000. The Company also adjusted its proposed EDIT Rider decrement to year 1 revenues to ($12,802,000), for a net increase of $55,699,000. Subsequently, the Company entered into an agreement with ORS concerning the recovery of certain expenses and other accounting adjustments. Thus, the Company's requested net revenue increase in this proceeding is $55,699,000 as adjusted per the terms of the 2018 DE Progress Rate Case Stipulations, as discussed further herein.

DE Progress submitted evidence in this case with respect to revenue, expenses and rate base using a test period consisting of the 12 months ended December 31, 2017, adjusted for certain known changes in revenue, expenses, and rate base.

Need for Rate Increase

Company witness Ghartey-Tagoe testified that the Company's need for a rate increase is driven by capital investments and environmental compliance progress made by the Company since the 2016 Rate Case. (Tr. Vol. 3, p. 292.) Such investments include further implementation of the Company's generation modernization program, which consists of retiring, replacing, and upgrading generation plants, investments in customer service technologies, and the Company's continued investment to maintain its transmission and distribution system.[13] (Application at 5-6). Witness Ghartey-Tagoe detailed the Company's recent investments driving the Company's requested rate increase. (*Id*. at 298-13 – 298-14.) He described numerous nuclear, fossil, hydro,

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[13] *See also* Tr. Vol. 4, p. 638-13 – 638-25 (testimony of Company witness Oliver regarding the Company's capital investment in its transmission and distribution infrastructure).

and solar projects that DE Progress has completed since its last rate case explaining that the Company has invested approximately $101 million in new gas-fueled generation.[14] (*Id.* at 298-13 – 298-14.) For example, he described the Company's new Sutton Combined Cycle plant, which provides an additional 78 MWs of capacity to the Company's fleet. (*Id.* at 298-13.) The two combustion turbines for the Sutton plant are critical components of the Company's ability to restart the generation system in the event of a catastrophic storm or outage. (*Id.*) In addition, the Company has invested $100 million in capital additions at the Roxboro Station to convert a dry bottom ash system to comply with federal requirements related to CCRs. (*Id.* at 298-14.)

Witness Ghartey-Tagoe further explained that environmental costs associated with compliance with new regulations relating to the management and storage of coal combustion residuals is also a driver for the Company's rate increase request. Duke Energy recycled more than 78 percent of coal combustion byproducts in 2017, and that includes DE Progress recycling or beneficially reusing the ash that is produced at the Company's coal-fired plants. (*Id.* at 292.) The Company has worked hard to reduce its impact on the environment by retiring older, less efficient coal plants across the Carolinas and has retired all of its coal plants in South Carolina. (*Id.* at 293.) Now the Company is closing all ash basins as part of new, sweeping state and federal regulations and as part of Duke Energy's commitment to provide increasingly reliable, cleaner power to customers at reasonable rates. (*Id.*) The Company is requesting to recover previously incurred coal ash compliance over a five-year period resulting in a revenue requirement of approximately $13 million. (*Id.* at 298-14.) The Company expects to continue to incur significant

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[14] *See also* Tr. Vol. 4, p. 568-4 – 568-6 (testimony of Company witness Turner (adopting the Direct pre-filed testimony of Company witness Miller) regarding the Company's capital investment in its fossil/hydro/solar generation assets); Tr. Vol. 4, p. 578-7 – 578-11 (testimony of Company witness Henderson regarding the Company's investment in its nuclear generation assets).

amounts of CCR environmental compliance costs after the December 2018 cut-off period in this case and is requesting continuation of the deferral of CCR compliance-related costs. (*Id.* at 298-17.).

Since the last rate case, the Company has also made investments designed to improve reliability and customer service. Mr. Ghartey-Tagoe testified that the Company expects to complete the next deployment phase of new AMI meters by the end of 2020 that will complement its investment in the on-going deployment of the new billing and CIS system known as Customer Connect which will give customers more information and service options as explained more fully in the testimony of Company witnesses Hunsicker and Schneider. (Tr. Vol. 3, p. 298-21 – 298-22.) The Company is also requesting amortization of regulatory assets related to the Harris Nuclear Station Combined License application, grid investments, rate changes from the most recent depreciation study, compliance with NRC requirements in response to cybersecurity requirements and events at the Fukushima Daiichi Nuclear Power Station in Japan, and the deferred costs associated with the filing of notices of application and withdrawal, along with other utilities in the state, to form a Regional Transmission Organization as further explained in the testimony of Company witness Bateman. (*Id.* at 298-14.) Mr. Ghartey-Tagoe also outlined the Company's proposal for a fee-free credit/debit card program for residential customers and request to recover the costs associated with the such a program from all customers through all rates. (*Id.* at 298-22 – 298-24.)

Witness Ghartey-Tagoe testified that the impact of the Tax Cuts and Jobs Act of 2017 ("Tax Act" or "TCJA") had also been incorporated into the Company's request and explained the Company's proposed EDIT Rider to flow back to customers excess deferred income taxes resulting from the change in the federal corporate income tax rate in a manner that maintains the Company's financial strength. (*Id*. at 298-15.) He explained that the Tax Act balances applied in this case include an offset to Distributed Energy Resource Program costs that have yet to be recovered that total $13 million as of September 30, 2018. (*Id.*)

Witness Ghartey-Tagoe testified that electricity in South Carolina is still an excellent value, even with the Company's proposed investments. (*Id*. at 298-25). He explained that while other consumer goods such as gas prices have risen over the past year, the cost of electricity in the Southeast has dropped 2.6 percent from September 2017 to September 2018. (*Id.*) Mr. Ghartey-Tagoe testified that even with DE Progress' proposed adjustment, its customers will continue to pay competitive rates. (*Id.*)

Witness Ghartey-Tagoe also described the Company's ongoing efforts to mitigate customer rate impacts. (*Id*. at 298-26 – 645-28.) He noted that through fuel diversity and prudent management the Company has been able to manage its costs as well as through significant cost containment measures. (*Id.*) He stated that to help customers reduce bills, the Company is continuing to expand and enhance its portfolio of Demand Side Management ("DSM") and Energy Efficiency ("EE") programs. (*Id*. at 298-27.) According to witness Ghartey-Tagoe, the Company offers customers more than a dozen energy-savings programs for every type of energy user and budget; EE programs currently save its customers in the Carolinas 1.7 billion kWh annually or more than $170 million, which is about 4% of total retail kWh sales. (*Id.* at 298-27 – 298-28.) Combined, the Company's EE and DSM programs offset capacity requirements by the equivalent of approximately more than four power plants. (*Id.* at 298-28.) Witness Ghartey-Tagoe also described the Company's Neighborhood Energy Saver Program, which is a residential EE program targeted at low-income customers that includes direct installation of a number of EE measures installed at no direct cost to the customer, potentially saving the average household over $45 per year on energy costs. (*Id.*) Witness Ghartey-Tagoe also discussed the Company's Energy Neighbor Fund which helps low-income individuals and families cover home energy bills and has provided approximately $3.2 million in assistance to DE Progress' customers in South Carolina. (*Id.* at 298-29.) Mr. Ghartey-Tagoe explained that the Company wants to continue making meaningful contributions to the well-being of the state and that is why he continues to advance ideas such as the "round-up" program that was suggested by Commissioners Ervin and Howard to provide additional help to the Company's most vulnerable customers. (*Id.* at 234, 305.) He also explained that the Company allows customers a bill management option that allows them to spread out the impacts of seasonal fluctuations into 12 equal monthly payments. (*Id.* at 298-30). The Company also offers payment arrangements to eligible customers who are having difficulty paying their entire bill by the due date. (*Id.*) Based on feedback received during the public hearings, the Company is looking at ways to better serve the farming community and reaching out to its agricultural customers to let them know of alternative rate schedules that might be more beneficial to those customers.[15] (Tr. 306.) Finally, this is only DE Progress' second base rate case in 30

[15] Although not an intervenor in this case, the South Carolina Farm Bureau Federation ("Farm Bureau") filed letters in this docket on April 9, 2019, and April 29, 2019, and Farm Bureau President Harry Ott testified at the April 1, 2019, public hearing in Florence, South Carolina, along with a number of other South Carolina farmers regarding the impact on the farming community of the Company's rate request and concerns regarding the proposed changes to the BFC. In a letter filed on April 30, 2019, DE Progress provided further explanation of actions it is taking to address the concerns raised by the Farm Bureau. Company witness Wheeler testified at some length at the evidentiary hearing on the issues raised by farmers and the Farm Bureau at the public hearings. (*See* Tr. Vol. 4, p. 740-746, 752-760, 766.) Mr. Wheeler explained that the Company had reviewed the farm accounts that are currently being served on the Medium General Service ("MGS") rate and found a total of 76 accounts. The Company reviewed those accounts and determined that 59 of them were eligible and would benefit from being moved to a different rate schedule, either Small General Service or the Seasonal Intermittent rate which was established largely to benefit seasonal power users including farmers. Witness Wheeler also explained that the 17 remaining accounts on the MGS rate were the largest farming accounts on the DE Progress system in South Carolina with average billings in the range of $800 per month. Witness Wheeler explained that because of the usage levels of these accounts the increased BFC would still only represent approximately 2.5% of the bills paid by that group. Notably, the variable portion of the bill is lower because of the higher BFC. Witness Wheeler testified about the Company's efforts to communicate with those of its farming customers who will benefit from moving to a different rate schedule. The Company has reached out to those customers and will continue to provide assistance to those and other farming customers. In addition, the Company has designated its Business Solutions Manager focused on South Carolina customers, to serve as a dedicated point of contact for the

years. (*Id.* at 233.) The Company went from 1988 to 2016 without a base rate case increase in South Carolina and delayed other recovery until this case to hold down costs and rates. (*Id.*) The Company recognizes there is a never a good time for a rate increase, and that is why the Company constantly looks at cost controls and efficiencies to keep rates lower than they would otherwise be and why the Company continues to pursue programs EE, or otherwise, to better allow customers to manage their usage. (Tr. 235-36.)

Witness Ghartey-Tagoe indicated that the Company's most important objective is to continue providing safe, reliable, affordable, and increasingly clean electricity to its customers with high quality customer service, both today and in the future. (*Id.* at 298-38.) He stated that Duke Energy has hundreds of thousands of customers in South Carolina, with approximately 170,000 in the DE Progress service territory and he is proud of the Company's service to customers. (*Id.* at 311.) For example, based on the J.D. Power's Customer Satisfaction Study, if DE Progress in South Carolina was measured as a stand-alone utility, it would rank at or near the top of large utilities in the southern United States for the past three years. (*Id.*) In fact, DE Progress customer scores in South Carolina have consistently surpassed national top quartile performance thresholds on the overall customer satisfaction index metric as well as within all six measured component areas, including power quality and reliability, price, billing and payment, communications, corporate citizenship and customer service. (*Id.*) Further, according to the J.D. Power Electric Utility Business Studies, Duke Energy South Carolina, if measured as a stand-alone utility, would have finished in the top quartile among large utilities nationally since 2016. (*Id.*) Witness Ghartey-Tagoe concluded that the request for a rate increase is made to support

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Farm Bureau and the farming community and anticipates that the designation of a specific point of contact will improve communications and assist farming customers to find the best rate.

investments that benefit DE Progress customers, and the Company strives to ensure that those investments are made in a cost-effective manner that retains the Company's level of service and competitive rates. (*Id.*)

The Commission finds and concludes that these investments by the Company provide significant benefits to all of its customers. They are necessary for the Company to continue to provide safe, adequate, and reliable electric service, and safe, adequate, and reliable electric service is essential to the well-being of the people, businesses, institutions, and economy of South Carolina. The Commission notes that no credible or substantial evidence was presented disputing the prudency, reasonableness, or necessity of the improvements which are reflected in the Company's request for a rate increase, as well as their cost.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NOS. 9-12

The evidence in support of the findings of fact are found in the verified Application, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

Return on Equity / Cost of Equity Capital

In its Application, DE Progress noted that its evidence, particularly the analyses prepared and submitted by Company witness Hevert, supported a return on equity of 10.75%. However, as a rate mitigation measure and in recognition that a rate increase may create hardship for some customers, the Company requested approval for its rates to be set using an ROE of 10.5%. For the reasons set forth herein, the Commission finds that an ROE of 10.5% is just and reasonable.

One of the principal (and often most contentious) issues to be decided in any ratemaking determination is the proper return to be allowed on the common equity invested in the regulated utility. As the Commission very recently observed:

> While the cost of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated

> based on observable market information and by applying recognized financial models to market-based data. By their nature, those models produce a range of results, from which the market-required ROE must be determined. *The key consideration in determining the ROE is to ensure the overall analysis reasonably reflects investors' view of the financial markets in general, and the subject company (in the context of the proxy companies) in particular*.

Order Addressing South Carolina Electric & Gas Nuclear Dockets, Docket Nos. 2017-207-E, 2017-305-E, and 2017-370-E, PSCSC Order No. 2018-804 (Dec. 21, 2018) ("*SCE&G Order*") at 83-84 (emphasis added). The importance of reflecting the *investor's* view is based on the fact that the capital markets are highly competitive, and that the Company competes for capital in those markets. Investors have multiple alternative investment choices and take into account authorized ROEs in selecting among those competing investment opportunities. Setting ROE too low, therefore, simply raises the cost of capital, in that investors will take the low authorized ROE as a signal to shift their investments elsewhere.

The legal standards applicable to the ROE determination reflect the centrality of setting ROE in light of investor requirements and expectations in competitive capital markets. These standards are set forth in *Hope* and *Bluefield*. These standards were adopted by the South Carolina Supreme Court in *Southern Bell Tel. & Tel. Co. v. S.C. Pub. Serv. Comm'n*, 270 S.C. 590, 595-96, 244 S.E.2d 278, 281 (1978). The Court stated:

> What annual rate will constitute just compensation depends upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should

> be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties ….

Southern Bell Tel., 270 S.C. at 595-96, 244 S.E.2d at 281 (quoting *Bluefield*, 262 U.S. at 692-93).

These cases also establish that the process of determining rates of return requires the exercise of informed judgment by the Commission. The South Carolina Supreme Court has held that:

> [T]he Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its ratemaking function, moreover, involves the making of "pragmatic adjustments." … Under the statutory standard of "just and reasonable" it is the result reached not the method employed which is controlling. … The ratemaking process under the Act, *i.e.,* the fixing of "just and reasonable" rates, involves the balancing of the investor and the consumer interests. Thus we stated in the *Natural Gas Pipeline Co.* case that "regulation does not insure that the business shall produce net revenues." … [B]ut such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on debt and dividends on the stock. … By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Southern Bell Tel., 270 S.C. at 596-97, 244 S.E. 2d at 281 (quoting *Hope*, 320 U.S. at 602-03). These principles have been consistently employed by the Commission and the South Carolina Courts. The Commission's "exercise of informed judgment" begins with its review and evaluation of the expert witnesses who testified concerning the cost of equity capital, to which the Commission now turns.

Company witness Hevert recommended in his direct testimony an ROE of 10.75%, which was slightly above the midpoint of his recommended range of 10.25% to 11.00%. (Tr. Vol. 5-2, p. 946-4 – 946-5.) Witness Hevert states that ROE, or the cost of equity:

> [I]s the return that investors require to make an equity investment in a firm. That is, investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm. From the firm's perspective, that required return, whether it is provided to debt or equity investors, has a cost. Individually, we speak of the "Cost of Debt" and the "Cost of Equity" as measures of those costs; together, they are referred to as the "Cost of Capital."
>
> The Cost of Capital (including the costs of both debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset, whether debt or equity securities, implies a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable risk investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk. In that important respect, the returns required by debt and equity investors represent a cost to the Company.

(*Id*. at 946-7 (emphasis in original).)

Witness Hevert noted that as all financial models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return requirements. (*Id*. at 946-8 – 946-9.) He therefore relied on three widely accepted approaches to develop his ROE determination: (1) the Constant Growth and Multi-Stage forms of the Discounted Cash Flow ("DCF") model; (2) the Capital Asset Pricing Model ("CAPM"); and (3) the Bond Yield Plus Risk Premium approach. He noted, however, weaknesses in the Constant Growth DCF Model and, therefore, discounted its results. As he explained, the model's assumption that the return estimated today will be the same required in the future does not square with the Federal

Reserve's recent moves towards unwinding its Quantitative Easing ("QE") policies. (*Id*. at 946-26 – 946-27; see also *id*. p. 946-67 – 946-68 (discussing impacts of the reversal of QE).)

The models (including the Constant Growth DCF Model) produced ROE results ranging from a low of 8.47% with the Constant Growth DCF Model (*id*. at 948-100) to a high of 11.67% in connection with one variant of the CAPM. (*Id.*) In tabular form, the full range of results from witness Hevert's quantitative analyses is as follows:

Table 7: Summary of Analytical Results

Constant Growth DCF	**Low**	**Mean**	**High**
30-Day Average	8.47%	9.33%	10.30%
90-Day Average	8.49%	9.35%	10.32%
180-Day Average	8.57%	9.43%	10.40%
Multi-Stage DCF (Gordon Growth)	***Low***	***Mean***	***High***
30-Day Average	8.71%	8.93%	9.19%
90-Day Average	8.73%	8.95%	9.21%
180-Day Average	8.81%	9.03%	9.30%
CAPM Results		**Bloomberg Derived Market Risk Premium**	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient			
Current 30-Year Treasury (3.03%)		8.36%	10.04%
Near Term Projected 30-Year Treasury (3.33%)		8.65%	10.33%
Average Value Line Beta Coefficient			
Current 30-Year Treasury (3.03%)		9.37%	11.37%
Near Term Projected 30-Year Treasury (3.33%)		9.67%	11.67%
ECAPM Results		**Bloomberg Derived Market Risk Premium**	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient			
Current 30-Year Treasury (3.03%)		9.71%	11.81%
Near Term Projected 30-Year Treasury (3.33%)		10.00%	12.11%
Average Value Line Beta Coefficient			
Current 30-Year Treasury (3.03%)		10.47%	12.81%
Near Term Projected 30-Year Treasury (3.33%)		10.77%	13.11%
	Low	**Mid**	**High**
Bond Yield Plus Risk Premium	9.93%	9.98%	10.17%

(*Id.* at 948-100.)

Witness Hevert provided extensive testimony concerning the capital market environment (*id*. p. 946-67 – 946-80) and addressed the effect those market conditions have on the return investors require in order to commit their capital to equity securities. In particular, witness Hevert draws attention to the Federal Reserve's "normalization of monetary policy," which the Fed indicates is its plan to return short term interest rates and the Fed's securities holdings to more normal levels, indicating of the Quantitative Easing policy the Fed adopted to combat the financial crisis and Great Recession of 2007-09. (*Id*. p. 948-11.) Reversal of Quantitative Easing has led to a generally higher interest rate environment. (*Id*. p. 948-10.)

Beyond generally rising interest rates as the Federal Reserve moves away from its QE program, witness Hevert pointed to two additional major factors in the capital market environment: (1) increased market volatility, including investor expectations that volatility will continue to increase as the Fed's QE policies are reversed; and (2) the cash squeeze impact of the Tax Cuts and Jobs Act upon utilities generally. (*Id*. at 946-72 – 946-80.) Both of these factors increase investor-perceived risk, which, witness Hevert concluded, should lead the Commission to "focus on the upper end of the range of analytical results." (*Id*. at 946-79.)

Based upon his econometric models, witness Hevert testified that the Company's cost of equity capital (*i.e.*, ROE) was in the range of 10.25-11.00%. (*Id*. at 946-80 – 946-81.) And while his capital market analysis led him to put emphasis on the upper range of those results, he also considered several Company-specific business risks in arriving at his final ROE recommendation. These risks include: (1) the risks associated with certain aspects of the Company's generation portfolio, including specifically issues relating to coal-fired generation (including coal-ash basin closure), nuclear generation, and regulations motivating distributed generation and net metering; (2) the Company's significant capital expenditure plan; (3) the risk associated with severe weather;

(4) the risk associated with the Company's regulatory environment; and (5) the cost of issuing common stock. (*Id*. at 946-42.) Taking into account these business risks, the capital market environment, and the results of his econometric modeling, witness Hevert's single-point ROE recommendation was 10.75%, just 12.5 basis points above the midpoint of his ROE range.[16]

The only intervenor witness to provide ROE testimony based on econometric modeling and analysis was ORS witness Parcell. His ROE recommendation was 9.3%. He utilized three methodologies: DCF, CAPM, and comparable earnings, which yielded the following results:

- Discounted Cash Flow (DCF)
    - Midpoint – 9.1%
    - Range – 9.0 – 9.2%
- Capital Asset Pricing Model (CAPM)
    - Midpoint – 6.45%
    - Range – 6.3 – 6.6%
- Comparable Earnings
    - Midpoint – 9.5%
    - Range – 9.0 – 10.0%

(Tr. Vol. 5-1, p. 801-4.) Witness Parcell discounted the CAPM results in his evaluation because the results produced were too low in his opinion. Accordingly, his single-point ROE recommendation resulted only from his DCF and Comparable Earnings analyses. The recommendation is a midpoint of the midpoints – that is, his 9.3% recommendation is the midpoint

[16] The Company's requested ROE (10.5%) is correspondingly 12.5 basis points *below* the midpoint of witness Hevert's ROE range.

between the 9.1% midpoint produced by his DCF method and the 9.5% midpoint produced by Comparable Earnings method. (*Id.*)

No other ROE econometric analyses were presented to the Commission. Walmart witness Chriss merely indicated that the Commission should "closely examine" the Company's ROE proposal (Tr. Vol. 5-2, p. 992-6) and, while acknowledging that decisions of other regulatory commissions do not "bind" this Commission (*id.* at 992-15), raises a concern that the Company's 10.5% proposed ROE "is counter to broader electricity industry trends" approved by other utility regulatory commissions in recent years. (*Id.* at 992-12.) He indicates that the average ROE for vertically integrated utilities authorized from 2016 to the present is 9.76%. (*Id.* at 992-13.)

The Commission has carefully evaluated all of the expert ROE evidence. It agrees with witness Hevert that all of the econometric models utilized by the experts have their own limitations, and, therefore, it is necessary to carefully review their results and to apply those results to "observable, relevant market information." (*Id.* at 946-13.) The Commission further agrees with witness Hevert that "[t]o the extent a given model's assumptions are misaligned with … [observable market] data, or its results inconsistent with basic financial principles, it is appropriate to consider whether other methods likely provide more meaningful and reliable results." (*Id.* at 946-67.) In doing so, the Commission also discharges its duty under the *Hope* "end result" test: "Under the statutory standard of 'just and reasonable' it is the *result reached* not the method employed which is controlling." *Hope*, 320 U.S. at 602, quoted in *Southern Bell Tel.,* 270 S.C. at 596. Indeed, witness Parcell appears to agree, in that he discarded his CAPM results as too low in light of prevailing capital market conditions. (Tr. Vol. 5-1, p. 801-46.)

The Commission is further persuaded by witness Hevert that the results of the experts' (both his and witness Parcell's) DCF analyses are also too low in light of current capital market conditions. These results do not adequately account for the Federal Reserve's policy reversals in recent years, and simply fail the *Hope* "end result" test. Inasmuch as witness Parcell continues to rely heavily upon his DCF analysis (apparently giving it equal weight to his Comparable Earnings analysis), the Commission questions the overall validity of witness Parcell's ROE recommendation.

The Commission finds witness Parcell's testimony to be problematic in several other respects. First, witness Parcell testified, in response to questions from counsel for Walmart, that ROEs have been trending downward. (Tr. Vol. 5-1, p. 811.) He benchmarked this observation against the 2007 timeframe, that is, from the time of the financial crisis and the Great Recession.[17] (*Id.*) He attributed this downward trend to two factors. First, he contends that interest rates have fallen since then (i.e., since 2007). (*Id.*) But judging against the timeframe of the Great Recession misleadingly skews the analysis. Rather, the relevant timeframe for comparison is from 2016, when the Company's previous rate case was decided. In that case, the Commission found that an ROE of 10.1% was appropriate and supportive of just and reasonable rates. When judged against the appropriate timeframe, witness Parcell's own data shows (*see* Hearing Ex. 36 (Exhibit DCP-2, Schedule 2)) that interest rates since 2016 have *risen*, not fallen. The Prime Rate, for example, was 3.51% in 2016, yet was 5.50% in January 2019, and the 10-year T-Note had a 1.86% yield in 2016, but had risen almost 100 basis points by December 2018. As witness Hevert observes, witness Parcell "has not explained what has changed so significantly that the Company's Cost of Equity has fallen by 80.00 basis points since its last rate proceeding … [in light of his data in

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[17] Witness Hevert agreed that authorized returns had fallen since 2007, but not since 2016. (Tr. Vol. 5-2, p. 982.)

Schedule 2 indicating that] the Prime Rate, Treasury bill yields, utility bond yields, and Treasury Bond yields (ten-year) all were higher in 2018 than in 2016." (Tr. Vol. 5-2, p. 948-10.)

Second, witness Parcell agreed with counsel for Walmart that regulatory mechanisms have been put in place that "reduce regulatory lag." (Tr. Vol. 5-1, p. 812.) The rating agencies disagree, however – as does the Commission. As witness Sullivan points out, Moody's cites regulatory lag as among several factors that could adversely the Company's financial metrics, which could in turn affect its credit ratings: "Moody's is particularly focused on downward pressure on financial metrics due to regulatory lag, including in the recovery of coal ash basin closure costs." (Tr. Vol. 5-2, p. 939-10.)

In addition, witness Parcell's testimony concerning the Company's credit ratings is also misleading. In response to questions from Commissioner Ervin, witness Parcell observed that DE Progress' "senior debt [was] rated AA2." (Tr. Vol. 5-1, p. 814.) This, as witness Sullivan noted, may be technically accurate (to the extent that witness Parcell was referring to senior *secured* ratings, i.e., those backed by first mortgage bonds), but is again the wrong metric. (Tr. Vol. 5-2, p. 955-56.) The correct metric is the Company's *unsecured* issuer and corporate ratings. Here, the Company is very firmly in the single A-rated category (*id*., p. 955), with Standard & Poor's rating at A-, the lowest rung of the single A ratings. (*Id.*) Further highlighting the misleading nature of witness Parcell's testimony, witness Sullivan observed that the Company's credit metrics for the year ended 2018 were more "challenged" than they have been in the previous four to five years (*id*. at 957), and also that it is important to note that the Moody's ratings have dropped from A1 to A2 over that period. (*Id.*)

Finally, once witness Parcell's DCF and CAPM analyses are discounted – the CAPM by his own action and the DCF in light of the Commission's adoption of witness Hevert's criticisms

– witness Parcell is left with only a single methodology for the estimation of the cost of the Company's equity capital, namely, his Comparable Earnings method, in which he estimated that the Company's ROE was in the range of 9.0-10.0%. The Commission has very recently held that it is "appropriate and reasonable to consider a range of estimates under *various* methodologies in order to more accurately estimate … cost of equity." *SCE&G Order*, at 90 (emphasis added). Basing results on a single analytical method, as the Commission would have to do were it to credit witness Parcell's testimony, is "inconsistent with decisions reached by regulatory commissions over the past several years and departs from the normal practice of estimating the Cost of Equity for utilities." (*Id*. at 89.) Accordingly, the Commission rejects witness Parcell's analysis.

In contrast, the Commission generally credits witness Hevert's testimony. His methodology is essentially the same as he employed in the recently concluded South Carolina Electric & Gas ("SCE&G") proceeding regarding the regulatory treatment of costs associated with SCE&G's recently abandoned nuclear development project in consolidated Docket Nos. 2017-207-E, 2017-205-E and 2017-370-E. In its order issued in that proceeding on December 21, 2018 – just over four months ago – the Commission specifically held that "the Commission finds that there is ample evidence and reason to conclude that the analyses conducted by Mr. Hevert are accurate and reliable estimates of SCE&G's cost of equity." *SCE&G Order*, at 89-90. Nothing in the last four months has changed the Commission's view of the accuracy or reliability of witness Hevert's mode of analysis.[18]

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[18] Witness Hevert withstood vigorous cross-examination seeking to portray his ROE recommendations as out of step with actual utility commission decisions. (*See*, *e.g.*, Tr. Vol. 5-2, p. 963-978 (examination by counsel for Walmart).) The Commission rejects this portrayal. First, as witness Hevert points out, many decisions by other commissions have set ROE within his recommended range, or within a few basis points of that range. (*Id*., p. 965.) Further, as he testified, commissions seek to balance all kinds of factors in their ultimate ROE determinations, while he, as an ROE expert witness, provides his opinion to those commissions on his view of the utility in question's cost of capital. (*Id*., p. 973.) Accordingly, it is not in the least bit unusual for the authorized ROE ultimately selected by a commission to

Intervenors such as Walmart do not propose an ROE, but assert that the Commission should look to the average of ROEs authorized by utility commissions in recent years to set ROE. This methodology is not the result of the type of rigorous cost of capital analysis the Commission expects.

The Commission recognizes that ROE is a cost to the utility – it is the cost of equity capital, that the Company must bear in order to provide service to the public and afford the Company an opportunity to earn a fair return on the investment it makes in providing that service. The Commission must determine this cost, just like it determines the prudence and reasonableness of other costs incurred by the Company. As Company witness Ghartey-Tagoe testified in response to cross-examination by counsel for Walmart:

> I think the Commission should look at the evidence presented in this case. I think the law actually prevents the Commission from just looking around the country and saying, "This utility's costs for X is $10. So that should be Duke Energy's cost. This utility's cost for putting out poles and wires is $20, so that should be Duke Energy's costs." I think the law requires the Commission to determine Duke Energy's specific costs.
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> * * *
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> That's why commissions depend on experts to evaluate the marketplace. They use proxy groups; they use different methodologies and come up with recommendations. And it's up to the Commission, which is an expert in itself, to determine what that number should be.

(Tr. Vol. 3 p. 345-46.) The Commission agrees. The Commission is charged with the exercise of informed judgment, which is the essence of the *Hope* "end result" test. Simply accepting an

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be different from an ROE expert's point recommendation, or even the expert's recommended range. Finally, the Commission agrees with witness Hevert that the analysis is simply not meaningful. As he put it in responding to counsel for Walmart, "I don't think the Commission should use the data that you have here [Exhibit 38], given [its] limitations …." (*Id*., p. 974.)

average of authorized ROE decisions by other commissions, even if that average happens to fall within the range of ROE recommendations proffered by a single cost of capital estimation methodology,[19] is decidedly not the "exercise" of informed judgment. To the contrary, it is the *abdication* of informed judgment.

The Commission set the Company's rates in its last rate case based upon a 10.1% ROE. There is no credible evidence supporting a 40+ basis point reduction (a fully 80 basis points reduction under the ORS analysis) in the Company's cost of equity capital in the intervening years. To the contrary, current capital market conditions are pointing in the opposite direction based upon a generally higher interest rate environment, increased and increasing debt and equity market volatility, and pressure upon utility credit metrics following passage of the Tax Act.

Accordingly, the Commission accepts witness Hevert's analysis that the Company's cost of equity capital is in the range of 10.25-11.0%. The Company has requested that rates be set based upon an ROE of 10.5%, which is well within that range and, indeed, 12.5 basis points below the midpoint of that range. Based upon the record in this proceeding, the Commission finds 10.5% to be a reasonable ROE for the Company in this case.

The Commission notes further that its approval of an ROE at the level of 10.5% – or for that matter, at any level – is not a guarantee to the Company that it will earn an ROE at that level. Rather, as South Carolina law demands, setting the ROE at this level merely affords DE Progress the opportunity to achieve such a return. The Commission finds and concludes, based upon all the evidence presented, that the ROE provided for here will indeed afford the Company the

[19] The 9.76% average ROE that Walmart appears to advocate is within the range (9.0-10.0%) of witness Parcell's Comparable ("CE") earnings methodology. But the Commission agrees with witness Hevert that witness Parcell's application of the CE methodology is flawed, and, were it to be corrected, the analysis would yield a result in the range of 10.5-11.0%. (Tr. Vol. 5-2, p. 982-983.) The Commission's 10.5% ROE determination is of course in that (corrected) range.

opportunity to earn a reasonable and sufficient return for its shareholders while at the same time producing rates that are fair to its customers.

Capital Structure

In its Application, DE Progress proposed using a capital structure of 53% members' equity and 47% long-term debt. The 53/47 structure is supported by the evidence presented by Company witness Sullivan, who indicates that its adoption will support the Company's long-term credit quality and financial strength. (Tr. Vol. 5-2, p. 946-3 – 946-19.) No party objects to the proposed 53/47 structure, and no party has introduced any evidence suggesting that structure is not just and reasonable.

Accordingly, based on the record in this proceeding, the Commission finds 53% equity and 47% debt to be a reasonable capital structure for DE Progress in this case.

Cost of Debt

The rebuttal testimony and exhibit of Company witness Sullivan indicates that the Company's cost of debt, to be applied to the approved capital structure so as to derive an approved overall rate of return, is 4.16%. (*Id*. at 946-3 – 946-5; Hearing Ex. 45 (Sullivan Rebuttal Ex. 1).) In his surrebuttal testimony, ORS witness Parcell indicated he accepts the Company's cost of debt as of December 31, 2018 of 4.16%. (Tr. Vol. 5-1, p. 803-17.) No party disputes the 4.16% cost of debt, and the Commission accepts this testimony and evidence.

Accordingly, based on the record in this proceeding, the Commission finds 4.16% to be a reasonable cost of debt for the purposes of this case.

Overall Rate of Return

The Commission finds that DE Progress, through sound management, shall have the opportunity to earn an overall rate of return of 7.52%. This overall rate of return is derived from applying an embedded cost of debt of 4.16% and an ROE of 10.5% to a capital structure consisting of 47% long-term debt and 53% equity. The Commission finds and concludes that evidence in this case supports DE Progress' overall rate of return, cost of debt, ROE, and capital structure.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NOS. 13-39

The evidence in support of the findings of fact are found in the verified Application, DE Progress 2018 Rate Case Stipulations, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

The South Carolina Supreme Court has concluded that adjustments to the test year should be made for any known and measurable out-of-period changes in expenses, revenues and investments that would materially alter the rate base. *Parker*, 313 S.E.2d at 292. As explained by the Court, "[t]he object of the test year is to reflect typical conditions. 'Where an *unusual* situation exists which shows that the test year figures are *atypical* the [Commission] should adjust the test year data.' Any other standard would negate the aspect of finality created by a test year time limitation." *Id*. The Commission's findings regarding the adjustments to the test year data as proposed by the Company and other parties follows:

Company witness Bateman explained that DE Progress made certain accounting and pro forma adjustments to actual operating income and rate base for the Test Period to reflect known and measurable changes in order to: (1) normalize for abnormal events; (2) annualize part year recurring effects to a full year effect; and (3) show actual changes in costs, revenues or the cost of the Company's property used and useful, or to be used and useful within a reasonable time after the Test Period, in providing service. (Tr. Vol. 3, p. 320-5.) These adjustments are reflected in Hearing Ex. 14 (Bateman Exhibit 1) and Hearing Ex. 17 (Bateman Rebuttal Exhibit 1) and are further described in the testimony of Company witnesses Bateman, Ward and Wheeler. The ORS' responses to these adjustments and additional adjustments recommended by the ORS, are reflected in Audit Exhibit KLM-2, and Surrebuttal Audit Exhibit KLM-2, and are further described in the testimony of ORS witnesses Major, Morgan, Payne, and Seaman-Huynh.

A. Agreed Upon Adjustments

In her rebuttal testimony, Company witness Bateman noted that DE Progress and the ORS agree on the following thirteen accounting adjustments proposed by the Company in its initial filing:

- Adjustment #1 – Annualize Retail revenues for current rates
- Adjustment #2 – Update fuel costs to approved rate and other fuel related adjustments
- Adjustment #3 – Adjust Other Revenue
- Adjustment #5 – Eliminate unbilled revenues
- Adjustment #6 – Adjust for costs recovered through non-fuel riders
- Adjustment #9 – Annualize property taxes on year end plant balances
- Adjustment #10 – Adjust for new depreciation rates
- Adjustment #12 – Remove NCEMPA Acquisition Adjustment
- Adjustment #13 – Remove expiring amortization credits from last year
- Adjustment #16 – Adjust for coal inventory
- Adjustment #24 – Levelize nuclear refueling outage costs
- Adjustment #26 – Adjust aviation expenses
- Adjustment #34 – Adjust for tax rate change

(Tr. Vol. 3, p. 326-3 – 326-4.)

In addition, Company witness Bateman noted there are five recommended adjustments, by the ORS, with which DE Progress agrees. (*Id*. at 326-4.) These adjustments reflect the update of estimates to actuals and additional adjustments to the Company's cost of service as shown on Hearing Ex. 15 (Bateman Supplemental Exhibit 1), and are incorporated in Hearing Ex. 17 (Bateman Rebuttal Exhibit 1):

- Adjustment #8 – Annualize depreciation on year end plant balances
- Adjustment #11 – Adjust for post year additions to plant in service
- Adjustment #23 – Update benefit costs
- Adjustment #31 – Adjust vegetation management expenses
- Adjustment #37 – Adjust for Allocation of PUC License Tax Expense

(*Id*.)

The adjustments listed in this Section have been agreed to by DE Progress and the ORS, and are not contested by any of the Parties. The Commission finds that these adjustments are just and reasonable to all Parties in light of all the evidence presented.

B. Stipulated Adjustments

The Company and the ORS also entered into a stipulation to address the following accounting adjustments:

- Adjustment #15 – Adjust Reserve for End-of-Life Nuclear Costs
- Adjustment #20 – Normalize for Storm Costs
- Adjustment #21 – Normalize O&M Non-Labor Costs
- Adjustment #25 – Amortize Rate Case Costs
- Adjustment #28 – Adjust for Credit Card Fees
- Adjustment #39 – Remove Nuclear Materials and Supplies Inventory

(*See* ORS Stipulation.)

Adjustment #15 – Adjust reserve for end of life nuclear costs

DE Progress requested an adjustment (Adjustment #15) to depreciation and amortization expenses to establish a reserve for end-of-life ("EOL") nuclear materials and supplies ("M&S") and unused last core nuclear fuel costs. (Tr. Vol. 3, p. 320-17 – 320-18). Company witness Bateman outlined the Company's proposal in her direct testimony, explaining that nuclear plants have EOL costs that are not captured in the decommissioning study. (*Id.* at 320-17.) These costs, which are distinct from the nuclear decommissioning costs that are held in trust, include the write-off of M&S costs that are in inventory at the time of decommissioning but do not have significant salvage value as well as the unused value of the last cores of nuclear fuel that will be in each plant at EOL. (*Id.* at 320-17 – 320-18, 431, 433.) The Company's proposal included a $2.2 million annual accrual for M&S inventory and a $0.7 million annual accrual for nuclear fuel (South Carolina retail). (*Id.* at 320-17 – 320-18.) The M&S and nuclear fuel amounts were each calculated by dividing the projected inventory amount and unused value of the last core at decommissioning by the number of years remaining on each unit's life and then summing for DE Progress' three nuclear plants. (*Id.)* The annual accrual amounts can be reviewed and adjusted, if needed, in each future general rate case before the end of the plant's life. (*Id.* at 320-18.) The reserve, once it is created, will be included as an offset to rate base in the cost of service, and the pro forma decreases rate base to reflect one year's worth of the accrual. (*Id.*) Witness Bateman explained that this approach creates a better matching of cost and benefit for ratemaking purposes. (*Id.* at 320-17 – 320-18.)

ORS witness Morgan recommended that the Commission reject the Company's request to establish reserves for EOL nuclear costs and last core nuclear fuel. (*See* Tr. Vol. 7, p. 1319-3 –

1319-4.) Witness Morgan contends that (1) the EOL fuel and parts inventory estimates included in the proposal are not known and measurable and (2) the retirement date for the three nuclear units is uncertain. (*Id.*) Moreover, witness Morgan reasoned that it is not equitable for today's customers to pay for costs related to nuclear plant retirements that may or may not occur in the next fourteen years. (*Id.* at 1319-4.)

On rebuttal, DE Progress opposed ORS' position on the EOL reserve. (Tr. Vol. 3, p. 326-25.) Witness Henderson responded that the Company's proposed EOL reserve for M&S inventory and nuclear fuel were calculated appropriately and are in the best interest of customers. (Tr. Vol. 4, p. 580-3.) Regarding nuclear fuel, the Company used current forecasts to calculate the estimated value of the remaining underutilized fuel in the last core. (*Id.* at 580-4.) Due to nuclear fuel cycling operations, approximately 2/3 of the last core will be underutilized at decommissioning. (*Id.* at 580-5.) For M&S inventory, the Company used the existing inventory balance at the end of the test period as the estimate of inventory remaining on the last day of operation. (*Id.*) Importantly, witness Henderson noted that nuclear plants must be fully maintained for safety purposes until removed from service, and inventory must be available to support that mission through the last day of operation. (*Id.*)

Witness Henderson also clarified that the proposed EOL accrual is based on operation of the Company's nuclear plants through the end of their presently licensed life. (*Id.* at 580-7.) Under NRC regulations, the initial operating life for a nuclear power plant is limited to 40 years, with the possibility of renewals. 10 CFR 50.51(a). The NRC may approve license renewals for an additional 20 years at a time. 10 CFR 54.31(b). NRC approval of license renewal requests is not automatic and requires that the NRC make certain findings prior to approval. *See* 10 CFR 54.29. The NRC has approved one operating license renewal for the Company's nuclear units, which extended those licenses from 40 to 60 years. However, the Company has neither filed an application for nor received NRC approval for a subsequent license renewal ("SLR"), which could extend the units' licensed life up to 80 years. (Tr. Vol. 4, p. 580-6.) If the Company ultimately applies for and receives SLR for one or more of its nuclear units, the Company would be open to adjusting the accrual period to reflect shutdown dates based on a renewed license. (*Id.* at 580-7.) Waiting until the NRC adjudicates DE Progress' potential SLR applications would result in a shorter accrual period for the EOL reserve. (*Id.* at 623.)

On surrebuttal, ORS witness Morgan continued to oppose DE Progress' proposed EOL reserve accrual. (Tr. Vol. 7, p. 1323-2.) In witness Morgan's view, both the amount and timing of the EOL for the nuclear plants is uncertain. (*Id.*)

As witness Morgan correctly points out, there is uncertainty concerning the exact timing of EOL for the Company's nuclear plants and the value of the Company's unburnt nuclear fuel and M&S inventory at EOL. (*See id.* at 1319-3 – 1319-4.) However, we also credit the testimony of Company witnesses Bateman and Henderson regarding the reasonable manner in which the amounts requested by the Company and the timing of EOL for the nuclear plants were estimated. (*See* Tr. Vol. 3, p. 320-17 – 320-18; Vol. 4, p. 580-3.) Furthermore, this approach creates a better matching of cost and benefit for ratemaking purposes and can be adjusted in the future if warranted. (Tr. Vol. 3, p. 320-17 – 320-18.) Although not binding on this Commission, other jurisdictions have approved similar reserves for EOL nuclear costs. *See Order Approving Accruals for Nuclear Decommissioning*, Florida Public Service Commission, Docket Nos. 991931-EI; 990324-EI; 001835-EI (January 7, 2002); *Order Approving Nuclear Decommissioning Study*, *Assumptions & Setting Filing Requirements*, Minnesota Public Utilities Commission, Docket No. E-002/M-14-761 (October 5, 2015). Moreover, DE Progress obtained approval to accrue an EOL reserve from the North Carolina Utilities Commission ("NCUC") during DE Progress' 2012 rate case in North Carolina. (Tr., Vol. 3, p. 432.)

Paragraph 5 of the ORS Stipulation allows the Company to establish an EOL nuclear reserve fund as proposed by the Company in Adjustment #15. Per the ORS Stipulation, the Company shall adjust depreciation and amortization by $2,938,000, income taxes by ($733,000), working capital by ($2,938,00), and accumulated deferred taxes by $733,000 to adjust the reserve for EOL nuclear costs. The ORS Stipulation, when considered in its entirety, reflects a reasonable give-and-take compromise of the positions the Parties have taken with regards to the settled issues. Therefore, the Commission approves the Company's establishment of the EOL nuclear reserve fund, as provided for in paragraph 5 of the ORS Stipulation.

Adjustment # 20 – Normalize for storm costs

The Company initially proposed to adjust other O&M expense by $1,005,000 and income taxes by ($251,000) for storm restoration costs to normalize the costs to the average level of costs that the Company experienced over the past ten years. (Hearing Ex. 14. (Bateman Ex. 1, p. 3.) ORS witness Morgan testified that he believed that it was more appropriate to eliminate the expenses in the highest and lowest cost years and use an 8-year average. (Tr. Vol. 7, p. 1319-5.) The Company did not oppose this adjustment. (Tr. Vol. 3, p. 326-13.)

At dispute was the historic inflation adjustment the Company included in its storm restoration cost normalization adjustment, which the ORS opposed. (*Id.*) The Company's inflation adjustment to storm costs adjusted each storm cost year included in the ten-year average to be comparable to the test year on an inflation-adjusted basis. (*Id.*) The ORS asserted that the Commission should reject the inflation adjustment because it shifts all risk away from the Company and onto customers. (Tr. Vol. 7, p. 1323-4.) Company witness Bateman testified that

ORS' adjustment removing inflation is unreasonable and ignores the current costs to address storms, including expenses for contract labor, materials, staging, and logistics, which have all risen significantly over the past ten years. (Tr. Vol. 3, p. 326-13.) ORS maintained that the costs are speculative, not known and measurable, and based on generalized data for the economy. (Tr. Vol. 7, p. 1323-4.) The Company responded that the inflation adjustment is based on historical inflation over the past ten years, calculated at 14.22 percent over the ten-year period, and therefore is a known and measurable adjustment. (Tr. Vol. 3, p. 326-13 – 326-14.) The Company argued this adjustment is reasonable because contract labor costs alone have increased 25 percent from 2008 to 2017,[20] and the Company simply cannot hire workers today for the same rate it paid them in 2008. (*Id.* at 659-14.)

As part of the ORS Stipulation, the parties agreed to use a five-year average (removing the highest (2016) and lowest (2013) year) without any inflation adjustment. (ORS Stipulation, p. 2, para. 2). The Company also agreed that it will examine the feasibility and customer benefits of a storm damage reserve fund and shall provide a proposal for ORS to evaluate before the Company's next rate case. (*Id.*) Per the ORS Stipulation, Adjustment #20 is updated to adjust O&M expense by $1,018,000 and income tax by ($254,000). (*Id.*) The ORS Stipulation, when considered in its entirety, reflects a reasonable give-and-take compromise of the positions the Parties have taken with regards to the settled issues. Therefore, the Commission approves the adjustment to O&M expense by $1,018,000 and income tax by ($254,000) to normalize storm costs per the terms of the ORS Stipulation.

[20] This percentage is based on on-system contractor rates for 2008 and 2017. These are the contractors that DE Progress uses on its system on a regular basis, and relies upon when there is a storm event.

Adjustment #21 – Annualize O&M non-labor expenses

Company witness Bateman explained that this adjustment annualizes Test Period O&M expenses excluding fuel, purchased power, and labor costs to reflect the change in unit costs that occurred during this period. (Tr. Vol. 3, p. 320-24.) The Company proposes to adjust other O&M expense by $508,000 and income taxes by ($127,000) to reflect the impact of inflation on test year expenses. (Hearing Ex. 17 (Bateman Rebuttal Ex. 1, p. 3.) ORS witness Major testified that the ORS opposes this adjustment because adjustments for inflation are not known and measurable and the Company's adjustment is based on projected and estimated data. (Tr. Vol. 7, p. 1236-3.) In her rebuttal testimony, Company witness Bateman states that this is not true, and the Company maintains that its adjustment is appropriate. (Tr. Vol. 3, p. 326-14.) First, she explained that the purpose of the Company's proposal is not to project O&M expenses, but instead to annualize the impacts of inflation to an end of test period level. (*Id.*) The adjustment takes actual, known and measurable inflation metrics (Consumer Price Index and Producer Price Index) and compares the average of the test period to the end of test period metrics. (*Id.* at 326-14 – 326-15.) She testified that these metrics for the 2017 Test Period are historic, known and measurable, and publicly available from the U.S. Bureau of Labor Statistics. (*Id.* at 326-15.) Company witness Bateman added that this adjustment is very similar to the customer growth adjustment which the ORS has not rejected (ORS Adjustment #40). (*Id.*) She pointed out that both adjustments annualize impacts – one for customer growth and one for inflation – and both are appropriate to include. (*Id.*)

As part of the ORS Stipulation, in compromise and settlement of Adjustment #15, the parties agreed to use ORS' Adjustment #21 to remove the inflation adjustment to non-labor O&M. (ORS Stipulation, p. 3, para. 7.) The ORS Stipulation, when considered in its entirety, reflects a reasonable give-and-take compromise of the positions the Parties have taken with regards to the settled issues. Therefore, the Commission approves the ORS' Adjustment #21 per the terms of the ORS Stipulation.

Adjustment #25 – Amortize rate case costs

The Company has proposed to amortize the incremental rate case expenses incurred for this docket over a five-year period. (Tr. Vol. 3, p. 320-25.) The ORS recommended that the Commission disallow the Company's request to earn a return on its rate case costs during the amortization period because the costs are not capital in nature. (Tr. Vol. 6, p.1236-12.) In addition, ORS witness Major recommended that the Commission disallow certain rate case expenses due to alleged insufficient supporting documentation. (*Id.*) Specifically, the costs ORS has identified for disallowance are related to legal services provided by outside counsel and billed via an e-billing system. (Tr. Vol. 3, p. 326- 16.)

Company witness Bateman explained that DE Progress has used an e-billing system for several years, and e-billing systems are commonly used by large companies to increase administrative efficiency. (*Id.*) Ms. Bateman explained that instead of submitting paper invoices, outside vendors are provided credentials to access the e-billing system and input relevant billing information (date, matter, rate, hours, description of work performed, etc.) directly into the system. (*Id.*) Once the information is submitted, the Company attorney responsible for approving the expense reviews the submission and approves or denies the invoice. (*Id.*) When the Company receives a data request for billing data, the Company exports the data from the e-billing system into a Microsoft Excel spreadsheet which is supplied in response to the request. (*Id.*) In the case of legal invoices, the Company also must review the descriptions of work performed for privileged information prior to providing. (*Id.* at p. 326-16 – 326-17.)

In response to ORS concerns regarding the e-billing submissions, Company witness Bateman testified that the Company offered to provide the ORS additional information such as vendor affidavits to verify that the expenses are true and accurate, screenshots of the data in the system, or to redact the privileged information by hand, but the ORS failed to respond to the Company's offer. (*Id.* at 326-17.) On April 7, 2019, the Company supplemented its responses to relevant data requests with additional details further supporting actual rate case expenses contested by ORS witness Major, including matter name, matter ID, responsible attorney, vendor, rate, number of hours, amount and matter descriptions. (Hearing Ex. 71.) In conclusion, Company witness Bateman testified that the expenses are reasonable and prudent and no justifiable reason for disallowance was given. (*Id.*)

As part of the ORS Stipulation, the Company and the ORS agreed to the calculation of rate case expenses reflected in ORS' Adjustment #25 which includes actual rate case expenses received and verified by ORS through December 31, 2018. (ORS Stipulation, p. 2, para. 4.) Per the ORS Stipulation, the Company will continue to defer its rate case expenses incurred after December 31, 2018 and will continue to send invoices to ORS for an audit for confidence in the transactions given the issues raised in this case. (*Id.* at p. 2-3, para. 4.) For invoice documentation, the Company agreed that it will either submit paper invoices or the information requested below for electronic invoices consistent with the following:

(a) Electronic invoice detail;

(b) Confirmation of payment for the electronic invoice; and

(c) Affidavits from the vendor/counsel verifying the amounts are related to this rate case and are true and accurate.

(*Id.* at 3, para 4.) In addition, the ORS retains the right to spot check or sample rate case expenses, and request paper invoices or other supporting detail and the Company agrees it will obtain and provide them from the vendor/counsel unless not available. (*Id.*) ORS also reserves its right to challenge the inclusion of the unamortized rate case expense in rate base in the current and any future rate case proceeding. (*Id.*) The Commission finds and concludes that the Company and the ORS' agreement relating to rate case expenses, as set forth in Paragraph 4 of the ORS Stipulation, is just and reasonable to all parties in light of all the evidence presented. The Commission further finds that the Company's request to include its rate case expenses in rate base is just and reasonable and approved for the reasons discussed further herein regarding the Company's deferral accounting requests.

Adjustment #28 – Adjust for credit card fees

In its Application, DE Progress requests approval of a fee-free payment program for credit, debit and ACH payment methods used by the Company's residential customers to pay their electric bills. (Application at 18-19.) Currently, customers are required to pay a $1.50 convenience fee, collected by a third-party vendor, for payments made by a credit card. To offer this program, the Company proposes to pay these costs on behalf of its residential customers and recover these costs as part of its cost of service. Company witness Bateman describes in direct testimony the Company's proposal to adjust its O&M expense by $0.8 million to adjust for credit card fee expenses. (Tr. Vol. 4, p. 320-26.) Company witnesses Ghartey-Tagoe and Quick testified to the value and need for the customer-driven program.

While no party contested the value or benefits of the fee-free credit card program, the ORS proposes to remove the amount representing the Company's growth projections, approximately

$129,000, from the Company's proposed adjustment for credit card fees because, ORS argues, they are not known and measurable. (Tr. Vol. 6, p. 1236-12.)

In her rebuttal testimony, Company witness Quick testified that based on historical data, the Company has been experiencing an average of 10 percent year over year growth in the number of credit card transactions for bill payment. (Tr. Vol. 3, p. 478-7.) Further, according to her, based on industry research and benchmarking, the Company is projecting the annual percentage increase in the number of credit card transactions once the fee-free program is deployed to double to 20 percent in the first year of the program. (*Id.*) Therefore, the Company's growth projection is reasonable, appropriate and should be reflected in the Company's adjustment. Otherwise, as witness Quick testified, the Company will be penalized for offering a program designed to improve customer satisfaction with their payment experience by not having an appropriate amount reflected in rates to match the expected cost to administer the program. (*Id.*) At the hearing, witness Quick stated that the Company's analysis is further supported by the percentage growth in credit card transactions the Company actually experienced in calendar year 2018. (Tr. Vol. 4, p. 543.) As witness Quick testified, the Company experienced an increase in credit card transactions in 2018 of 22 percent, which is higher than the growth projection the Company is actually proposing to be reflected in the Company's adjustment. (*Id.*) She believes this is indicative of what the Company will see once the program is implemented and further supports the Company's need to embed an element of growth in the Company's adjustment.

As part of the ORS Stipulation, the parties agreed that the adjustment for credit card fees shall be reduced to reflect the actual number of credit card transactions experienced in 2018. The amount was calculated by reflecting the 2018 actual transactions of 449,456 times the $1.50 fee for a total of $674,184. (ORS Stipulation, p. 2, para. 3.) Accordingly, the ORS Stipulation provides that Adjustment #28 shall reflect an adjustment to O&M expense by $674,000 and income taxes by ($168,000) to reflect actual expenses for year end. The ORS Stipulation, when considered in its entirety, reflects a reasonable give-and-take compromise of the positions the Parties have taken with regards to the settled issues. Therefore, the Commission approves the adjustment for credit card fees as provided for in the terms of the ORS Stipulation.

Adjustment #39 – Remove Nuclear Materials and Supplies Inventory

ORS witness Morgan conducted a review of DE Progress' present nuclear M&S inventory. (Tr. Vol. 7, p. 1319-7.) Witness Morgan explained that M&S inventory includes spare parts needed for the operation of the nuclear plants and costs associated with future projects. (*Id.*) Some of the Company's M&S inventory items have remained in a hold status for more than four years. (*Id.*) The Company places M&S inventory on hold into different classifications including Repair Hold, QA Hold, Stores Hold, and Engineering Change Hold. (*Id.* at 1319-8 – 1319-9.) Witness Morgan testified that this excess nuclear plant M&S inventory cannot be used by DE Progress, and therefore, should not be recovered from DE Progress' customers and should be excluded from rate base. (*Id.* at 1319-7.) Consequently, witness Morgan recommended an adjustment to the Company's M&S inventory of approximately $17.38 million on a system basis to account for M&S inventory items that have remained on hold for more than 4 years. (*Id.*) Witness Morgan also noted that NCUC approved a similar adjustment to inventory items in a hold status during DE Progress' 2017 rate case in North Carolina. (*Id.* at 1319-7 – 1319-8.)

On rebuttal, DE Progress opposed ORS' proposed adjustment for M&S inventory on hold. (Tr. Vol. 3, p. 326-26.) Witness Henderson testified that the placement of an M&S inventory item in hold status for more than four years is not indicative that the items will not be used. (Tr. Vol. 4, p. 580-8.) The "hold" status ensures that the items will be properly evaluated prior to use, but it is incorrect to assume that items on hold for more than four years will not be used or available for use. (*Id.*) In fact, the inventory can be made available should priorities dictate applying the maintenance or engineering attention to the cause for the hold. (*Id.* at 580-8 – 580-9.) Witness Henderson further explained that several factors influence the amount of time that an item remains on hold. (*Id.*) Depending on the type of hold, these factors include whether the item must be sent off-site for repair, when the item will be needed, whether manufacturing of the item has been discontinued, difficulties resolving quality assurance issues with vendors, and the prioritization of the Company's financial and engineering resources. (*Id.* at 580-9 – 580-10.) Witness Henderson also disagreed with witness Morgan's characterization of how the NCUC resolved a similar issue. (*Id.* at 580-10 – 580-11.) Specifically, the issue of M&S items on hold was resolved through a settlement that reflected the give and take compromise of contested issues to reasonably balance customer interests in mitigating rate impacts with investor interests in providing for reasonable recovery of investments. (*Id.*) Furthermore, the North Carolina Public Staff's witness did not recommend excluding the value of Engineering Change Hold items that had remained in a hold status for greater than four years. (*Id.*)

On surrebuttal, ORS witness Morgan updated ORS' recommendation regarding M&S items on hold. (Vol. 7, p. 1323-5.) Recognizing that M&S items under "Engineering Change Hold" may be used in the future, ORS updated its proposed M&S inventory adjustment to $6.3 million (system). (*Id.*)

With regard to nuclear M&S inventory, it is appropriate in general to remove M&S inventory that cannot be used by DE Progress from the rate base, as witness Morgan advocated. (*See id.* at 1319-7.) However, witness Henderson accurately points out that an item remaining in a hold status for four years does not necessarily mean that the items will not be used. (Tr. Vol. 4, p. 580-8.)

In paragraph 6 of the ORS Stipulation, the Parties agree to ORS Adjustment #39, which adjusts nuclear M&S inventory by ($599,000) to remove nuclear M&S inventory at the Company's nuclear plants that have remained in a hold status for more than 4 years. The ORS Stipulation, when considered in its entirety, reflects a reasonable give-and-take compromise of the positions the Parties have taken with regard to the nuclear M&S inventory hold issue. Therefore, the Commission approves the adjustment of ($599,000) to nuclear M&S inventory, as provided for in paragraph 6 of the ORS Stipulation.

C. Adjustments relating to Deferrals

The differences in the Company's position and the ORS' position on the adjustments listed below are related to the treatment of deferrals:

- Adjustment #17 – Adjust previously deferred amounts – Harris COLA, GridSouth, Fukushima/Cybersecurity, 2014 Storms[21]
- Adjustment #19 – Amortize deferred cost balance related to SC AMI
- Adjustment #35 – Amortize deferred cost balance related to SC Grid

These adjustments are discussed in this Section.

For the following adjustments, not only does the Company oppose the ORS' recommended deferral treatment of these adjustments, the Company also opposes other aspects of the ORS' recommendations on these adjustments:

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[21] The Company's request to extend the previously approved deferrals related to the 2014 storms was addressed separately by the Commission in Docket No. 2019-26-E in Order 2019-126.

- Adjustment #18 – Amortize deferred environmental costs[22]
- Adjustment #25 – Amortize rate case expenses[23]
- Adjustment #30 – Adjust for Customer Connect Project additional expense and deferral[24]

As noted, these adjustments are addressed elsewhere in this Order.

Background On the Company's Requests for Deferral Accounting

The Company proposed to begin amortizing several deferred costs for which the Commission had previously granted accounting orders permitting the Company to defer the costs for consideration for cost recovery in the Company's next rate case. The Company has requested that the deferrals be included in rate base during the amortization period and that the Company be permitted to recover its weighted average cost of capital ("WACC") on the unamortized balance during the amortization period. These specific accounting adjustments include deferred costs for the following:

- **Adjustment #17** – Adjust previously deferred amounts – Harris COLA, GridSouth, Fukushima/Cybersecurity, 2014 Storms[25]
- **Adjustment #18** – Amortize Deferred Environmental Costs[26]
- **Adjustment #19** – Amortize Deferred Cost Balance Related to South Carolina AMI[27]
- **Adjustment #25** – Amortize rate case expenses

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[22] The costs the Company has incurred relating to environmental compliance – in particular, coal ash-related costs – are addressed in the Evidence for Findings and Conclusions Nos. 52-54.
[23] The Company's rate case expenses are discussed in Section B herein.
[24] The Company's Customer Connect Project expenses are discussed in Section D herein.
[25] Deferral for Harris COLA and Fukushima/Cybersecurity costs approved in Order No. 2014-138 in Docket No. 2014-472-E, costs for GridSouth deferred pursuant to Company's Joint Application filed in Docket No. 2011-139-E, and deferral for 2014 Storms approved in Order No. 2015-62 in Docket No. 2014-482-E.
[26] Deferral approved in Order No. 2016-490 in Docket No. 2016-196-E.
[27] Deferral approved in Order No. 2018-553 in Docket No. 2018-205-E.

- **Adjustment #30 –** Adjust for Customer Connect Additional Expense and Deferral[28]

- **Adjustment #35** – Amortize Deferred Cost Balance Related to South Carolina Grid[29]

In addition to the accounting deferrals noted above and already approved for deferral by the Commission, in its Application, the Company also requested an accounting order to: 1) continue the deferral for coal ash basin closure compliance costs after the cut-off date for this rate case of December 31, 2018 discussed further herein; 2) establish a regulatory asset at the time of the Asheville plant's retirement for the remaining net book value, and permission to defer to this regulatory asset any costs related to obsolete inventory, net of salvage, at the time of retirement; 3) continue the deferral for ongoing costs incurred in connection with the deployment of AMI in-service after December 31, 2018, and 4) approve deferral of the Company's on-going GIP costs.[30] (Application at 23-25.)

The requests for the ash basin deferral, AMI deferral and GIP deferrals are discussed further herein. The Company requested an accounting order for approval to establish a regulatory asset related to the retirement of the Company's Asheville coal plant originally expected to be fully depreciated by its expected retirement date in 2020. (Application at 24). To mitigate the rate impact to customers, the Company adjusted its depreciation rates to reflect recovery of the remaining net book value over a ten-year period, similar to the treatment of other coal plants that

[28] Deferral approved in Order No2018-553 in Docket No. 2018-205-E.
[29] Deferral approved in Order No. 2018-751 in Docket No. 2018-206-E.
[30] Per Order No. 2019-26H, we will establish a new and separate docket to review and consider the Company's Grid Improvement Plan per the GIP Stipulation entered into between the ORS and Company, on March 13, 2019. In addition, the Company proposed that in the event the Commission does not find it appropriate for the Company to increase O&M expense to recover the projected costs for its Customer Connect program, in the alternative, the Company requests that the Commission approve continuation of the deferral of the incremental operating expenses incurred related to the Customer Connect project, including a carrying charge on the deferred costs, until the Company's next general rate case. (Tr. Vol. 3, p. 326-19.). As discussed further in Section D herein, we find the Company's request to increase O&M expense for the Customer Connect program to be reasonable and appropriate and as a result, the Company's alternative request to continue the deferral for Customer Connect costs is not necessary.

were retired early in DE Progress' prior depreciation study. (*Id.*) Because the net book value of the plant will not be fully recovered at the time of retirement, the Company requests to include in rate base a regulatory asset at the time of the Asheville plant's retirement for the remaining net book value and the ability to continue amortizing the costs over the remaining portion of the ten-year period at that time. (*Id.*) The Company also requests permission to defer to this regulatory asset any costs related to obsolete inventory, net of salvage, at the time of retirement. (*Id.*)

Deferral accounting is one regulatory mechanism among a wide range of mechanisms for the Commission to use in setting rates as acknowledged by ORS witness Parcell. (Tr. Vol. 5-1, p. 801-19.) As noted by Company witness Bateman, deferral accounting is a mechanism that can be used to delay the Company's need to file a rate case. (Tr. Vol. 3, p. 331.) Deferrals can facilitate the implementation of new technologies, such as Smart Meters[31] and the Company's new billing system, known as Customer Connect,[32] and facilitate regulatory compliance, such as Fukushima and cybersecurity requirements.[33] Where such programs are in the customer interest, deferrals can and have been appropriate. Typically, this Commission has approved utility requests for deferral accounting orders for a number of items by issuing accounting orders with the caveat that the reasonableness of the deferred costs and mechanics of the cost recovery would be subject to review in a future rate case proceeding.[34] The issue of deferral accounting has typically been approached by the Commission on a case-by-case basis or through settlement, consistent with the regulatory

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[31] *See* Docket No. 2018-205-E, Order No. 2018-553 (2018).
[32] *Id.*
[33] *See* Docket No. 2013-472-E, Order No. 2014-138.
[34] *See Order No. 2014-138*, PSCSC Docket No. 2013-472-E, *In Re: Petition of Duke Energy Progress, Inc. for an Accounting Order for Deferrals Associated with Sutton, Fukushima, Cyber Security, Harris COLA & Decommissioning* (January 30, 2014); *Order No. 2009-254,* Docket No. 2009-55-E, *In Re: Petition of Duke Energy Carolinas, LLC, for an Accounting Order to Defer Certain Environmental Compliance Costs and the Incremental Costs Incurred from the Purchase of a Portion of Saluda River's Ownership in the Catawba Nuclear Station,* (April 9, 2009).

policy that the "just and reasonable rate is set by balancing the interest of the ratepayers and the right of the utility to earn a fair return."[35] The Commission has historically authorized deferral accounting for post-in-service costs of major generating plant additions from the date the units were placed in service to the date rates reflected the cost of the plants, and we have also permitted deferral accounting for abandoned plant.[36] In addition, we have authorized deferral accounting for significant O&M expenses incurred to comply with regulations such as new requirements for nuclear operating units after the Fukushima incident and new cyber-security requirements, finding the magnitude of the costs are material and could significantly impact the Company's earnings.[37] For example, we approved DE Progress' request for permission to adjust the level of decommissioning contributions applicable to South Carolina retail operations and defer in a regulatory liability account certain decommissioning expense credits, which were projected to be approximately $3 million annually to South Carolina retail operations. There, DE Progress asserted that the annual net costs it sought for the four deferrals in that petition were material and could substantially harm the Company's earnings if deferral accounting was not permitted. The Commission permitted deferral accounting of the decommissioning expense finding "[c]learly, it is reasonable that degradation of the Company's earnings be prevented; in so much as it is related to a lack of deferral of the regulatory assets and liability cited in the Company's Petition. Granting the deferrals will not preclude this Commission or any party from addressing the reasonableness

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[35] *S.C. Cable Television Ass'n v. S.C. Pub. Serv. Comm'n, et al.,* 313 S.C. 48 (1993) (citing *Southern Bell*, 270 S.C. 590).

[36] *See PSCSC Order No. 2014-138*, PSCSC Docket No. 2013-472-E, *In Re: Petition of Duke Energy Progress, Inc. for an Accounting Order for Deferrals Associated with Sutton, Fukushima, Cyber Security, Harris COLA & Decommissioning* (January 30, 2014).

[37] *Id.* (citing *Accounting Order No. 2012-780* (October. 25, 2012) ("This Commission approved South Carolina Electric & Gas Company's request to defer costs related to compliance with Fukushima-related regulation."); *see also Order Approving Increase in Rates & Charges & Settlement Agreemen*t, *Order No. 2013-661* (Sept.18, 2013) ("The deferral and amortization of operations and maintenance expenses to comply with Fukushima and Cybersecurity-related regulation were approved by this Commission.")).

of the costs deferred in regulatory asset and liability accounts in the next general rate proceeding."[38]

ORS Recommendation for Deferral Accounting Treatment in this Proceeding

In this proceeding, ORS witness Payne testified that the ORS will make a filing in 2019 to request a proceeding to adopt guidelines for future deferral accounting cost recovery requests. In general, witness Payne recommends that each deferral be separated into two categories of costs: operating-related costs and capital-related costs. (Tr. Vol. 6, p. 1245-4.) Mr. Payne recommends that the Company be allowed to recover prudently-incurred operating-related expenses which he considers to be O&M, depreciation expense and property taxes on plant-in-service, without WACC return or rate base treatment. (*Id.*) For capital-related costs which witness Payne defines as the deferred return on capital investments, he recommends that the Company be permitted to recover prudently incurred capital-related costs by recording capital-related costs to rate base and recovering those costs through depreciation expense over the life of the associated asset, while earning a WACC return on the undepreciated balance. (*Id.* at 1245-4 – 1245-5.) With the exception of the deferred environmental costs included in Adjustment #18, ORS recommends the Commission allow the Company to recover ("return of") its deferred expenses subject to its proposed guidelines concerning rate base treatment of operating-related and capital-related costs. Witness Payne testified the ORS recommendations for deferral accounting treatment are in the public interest because the recommendations allow for a return of costs, and where appropriate, a return on costs. (*Id.* at 1245-5.)

[38] *PSCSC Order No. 2014-138*, at 6.

Company witness Bateman addressed the specific accounting treatment proposed by the ORS for accounting deferrals as well as the ORS' suggested amortization periods. Company witness Bateman testified that the ORS recommendations for deferral accounting would deny the Company recovery of prudently incurred costs by only permitting a "return of" but not a "return on" the Company's deferred costs. (Tr. Vol. 3, p. 326-5.) Company witness Bateman explained that carrying costs on deferrals are necessary to ensure the Company recovers the full value and effect of the deferral. (*Id.*) Moreover, Company witness Bateman argued that even though no party contests the prudency of the expenses in the deferrals, ORS devalues the deferrals by disallowing carrying costs, and in most cases, significantly extending the recovery period for the deferred costs. (*Id.*) The Company opposes ORS witness Payne's recommendation to disallow the return on the incremental costs deferred in a regulatory asset during the *deferral period* pointing out that witness Payne offers no rationale for this proposed disallowance other than citing the portion of the deferral orders that states that "[s]uch relief will not prejudice the right of any party to address the prudency of such costs in a subsequent rate proceeding." (*Id.*) The Company also opposes the ORS' recommendation to disallow a return on the unamortized balance of the deferred costs during the *amortization period* for the portion of regulatory assets that relate to operating expenses. (*Id.* at 326-5 – 326-6.) The Company argues that the ORS recommendation further diminishes its recovery of prudent costs because of the longer amortization periods recommended by ORS witness Morgan, which Company witness Bateman explains increases the amount of disallowance as a result of the time value of money. (*Id.* at 326-6.) She explained that ORS' rationale is inappropriate and inconsistent because it treats the costs as if they are capital costs in terms of length of recovery but does not allow them to be placed in rate base or collect carrying costs like undepreciated capital would receive. (*Id.* at 326-7.) Moreover, ORS' rote application of a position to not allow a return on any "operating costs" belies any fact-specific inquiry germane to the expenses at issue. For example, the "operating cost" related to AMI would not exist but for the capital being deployed, which is also the case for the Customer Connect and grid-related deferrals in this case. Whether a cost by accounting definition is truly an "operating cost" or capital-related cost—as the operating expense is necessary to deploy the capital—should also be a factor relevant in a fact-specific inquiry.

ORS witness Payne argued that the ORS proposal is fair explaining that the Company would not have been permitted to earn a return on any of the costs had the costs not been approved for deferral treatment. DE Progress witness Bateman argued that Mr. Payne's logic is misplaced and inconsistent because there are carrying costs on regulatory liabilities that the ORS is willing to accept when they benefit customers. (*Id.* at 326-7.) To illustrate the inconsistency of ORS' recommendation, Company witness Bateman uses accumulated deferred income taxes ("ADITs") as an example. She explained that income taxes are an operating expense and deferred income taxes result from a timing difference from when the Company pays the cash for the expense and when the costs are recovered in customer rates, resulting in a regulatory liability. Deferred income taxes are included in rate base, thus the Company pays customers a carrying charge on the deferred tax balance. Yet, the ORS is not recommending those costs be removed from rate base which would be a significant detriment to customers by increasing the Company's rate base by 27 percent. (*Id.* at 326-8.) Company witness Bateman concludes that deferrals, by definition, recognize a cost that the Company is not currently recovering in rates. (*Id.* at 326-10.) She explained that those deferred costs, whether capital or operating-related, require cash that must be obtained by the Company's debt and equity investors and those investors require interest (a return on the deferred costs) on the cash they have invested in the Company. (*Id.*) Company witness Bateman testified that these financing costs are a real cost to the Company and thus by disallowing the financing costs, the Commission would be disallowing prudently incurred costs. (*Id.*)

Company witness Hevert addressed the financial consequences of ORS witness Payne's deferral accounting recommendation. Witness Hevert testified that if the Company is not allowed to include the "operating-related" deferred costs in rate base, the Company will suffer a negative net present value, which would be borne by investors. (Tr. Vol. 5-2*,* p. 948-95.) Witness Hevert analogized the Company's proposal to include operating-related regulatory assets in rate base to corporate finance discounted cash flow valuation which includes both a "return of" and "return on" to calculate the present value of an investment. (*Id.* at 948-96.) Mr. Hevert used bond valuation as an illustrative example and explained that to derive the present value of a five-year bond valued at $10 million, both the amortization (or "return of" principal) and the interest (or "return on") must be included to correctly calculate the value. (*Id.*) He explained that when interest, or the "return on," is excluded from the calculation, there is a significant reduction in the present value which equates to 13.41 percent in his hypothetical example. (*Id.*) Thus, Mr. Hevert argued that the amortization or "return of" the regulatory asset is not a "sufficient level of recovery" as Mr. Payne suggests; rather, because the Company has expended cash upfront for these operating costs, a carrying charge is necessary to fully recover the costs on a present value basis. (*Id.* at 948-97.) Mr. Hevert explained that carrying charges reflect the economic value required to avoid a loss in present value and absent the carrying charge, the Company's financial profile would be diminished. (*Id.*) Mr. Hevert also disagrees with Mr. Payne's categorization that deferred depreciation expense is an operating-related cost because Mr. Hevert views deferred depreciation expense as having financial implications analogous to capital-related costs, in that both represent a cash outlay that must be financed. (*Id.*)

Company witness Wright further adds that based on his experience, Mr. Payne's recommendation to disallow the recovery of a return on a large portion of the Company's deferred costs is inconsistent with the normal cost recovery allowed by regulatory bodies. (Tr. Vol. 5-1, p. 839-32.) Mr. Wright explains that the ORS' deferral accounting recommendations violate the basic regulatory compact which states that:

> A rate-regulated entity incurs costs in order to provide reliable service to customers within its approved service territory in a not unduly discriminatory manner **with the expectation that it will have the right to recover those prudently incurred costs, plus earn a fair rate of return on the capital that has been invested** in the business to support reliable utility service. (emphasis added).[39]

(*Id.*) Witness Wright disagrees with Mr. Payne's assertion that his deferral accounting recommendation "still allows the Company to recover its actual deferred costs"[40] because there is a cost of money that is a real cost that Mr. Payne's recommendation does not permit the Company to recover. (*Id.* at 839-33.) In addition, witness Wright explains that Mr. Payne's deferral accounting recommendation completely ignores the effect of inflation over time and this impact is further exacerbated by the ORS recommendations to stretch out the Company's proposed cost recovery amortization periods. (*Id.* at 839-34.) Dr. Wright concludes that he is concerned that Mr. Payne's recommendation disallowing a return on much of the Company's deferred costs would elicit a negative response from the investment community. (*Id.* at 839-35.)

In response to DE Progress witnesses Bateman, Hevert and Wright, ORS witness Payne opined that the ORS recommended accounting treatment for deferrals is a relatively minor

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[39] "Accounting for the Effects of Rate Regulation," Edison Electric Institute, July 2011, at 5; *see also Southern Bell*, 270 S.C. at 595 ("the governing principle for determining rates to be charged by a public utility is the right of the public on one hand to be served at a reasonable charge, and the right of the utility on the other to a fair return on the value of its property used in the service") (citing *Bluefield*, 262 U.S. 679).

[40] Tr. Vol. 6, p. 1245-5.

reduction to the Company's operating experience. (Tr. Vol. 6, p. 1247-3.) Based solely on the aspect of a return and rate base inclusion incorporating the same amortization periods as the Company and no change to the allowable coal ash costs, the ORS' deferral accounting recommendation only reduces the Company's revenue requirement by approximately $900,000. (*Id.*) However, Mr. Payne acknowledges that comparing ORS' proposal in its totality (including the ORS' recommended amortization periods and net impact to rate base) against the Company's proposal results in a difference in total revenue requirement of $36,538,000. (*Id.*) Further, at the hearing, Company witness Bateman testified that the Company does not agree that Mr. Payne's testimony regarding the aggregate impact of the deferrals captures the full financial impact to the Company. (Tr. Vol. 3, p. 329). She explained that Mr. Payne only calculates the annual impact, but the Company will be experiencing the disallowance over multiple years, so the total impact would be much larger, which the Company calculates as approximately three times as much. (*Id.* at 329-330.) Moreover, Ms. Bateman testified that the fact that an impact is relatively small is not in and of itself a legitimate basis for a disallowance, no more than it would be a legitimate reason for a proposed increase. (*Id.* at 330.) In addition, she offered that it is important for the Commission to keep in mind that the Company has deferred over a $150 million of deferred storm costs and those deferred storm costs have been removed from this case to mitigate the impact on customers. (*Id.*) However, she explained that if the ORS proposed deferral accounting guidelines were applied to those deferred storm costs, meaning no return on the deferred costs related to operating expenses, whether during the deferral or amortization period, that would be a significant impact to the Company. (*Id.*)

In his surrebuttal testimony, ORS witness Payne explained that the rates and revenue requirement are designed by the Commission to provide the Company a reasonable opportunity to recover prudently incurred O&M expenses and a fair and reasonable return on its capital investments to provide customers with reliable and high-quality service. (Tr. Vol. 6, p. 1247-5.) He argues that the rebuttal testimonies of witnesses Hevert, Bateman and Wright failed to acknowledge the Company collected $562,000,000 in operating revenues from South Carolina customers per the Application. (*Id.*) Witness Payne testified that these revenues were paid to the Company by South Carolina customers during the 2017 test year through service rates that were designed to allow recovery of the Company's operating costs as well as provide a reasonable return on shareholder's capital investments. (*Id.*) On cross examination, however, Mr. Payne conceded that the deferrals the Company is seeking recovery for in this case, for example, the Customer Connect and AMI deferrals, did not exist at the time of the Company's last rate case, and therefore those costs were not included in operating revenues that were established by the Commission following that last rate case. (*Id.* at 1293.) Thus, witness Payne conceded that the rates designed in the Company's prior rate case were not designed to recover the costs of the deferrals the Company is requesting recover for in this case. (*Id.* at 1294.) Moreover, based on Exhibit D to the Company's Application, during the Test Period, the Company only earned a 4.14 percent return on equity and a 4.10 percent rate of return on South Carolina retail rate base, versus the 10.1 percent return on equity and 7.20 percent rate of return it was authorized in the prior rate case. Therefore, the $562,000,000 collected in operating revenues from customers during the Test Period did not cover the Company's operating costs or provide a reasonable return on shareholder's capital investment.

Witness Payne testified that there is no statute or regulatory standard that ORS identified that governs recovery of a cost of capital return on a deferral balance; thus, the Commission has the duty to determine the most equitable treatment of the deferred balances for the Company and its customers. (*Id.* at 1247-3 – 1247-4.) ORS maintains that the Commission should apply the proper accounting treatment to the expenses contained in the deferral balances as it would absent the deferral account. (*Id.* at 1247-4). However, Mr. Payne admitted this is essentially a policy position and there is no accounting and financial requirement to do so. (Tr. Vol. 6, p. 1284.) In fact, ORS witness Payne even admitted it is a fair characterization to say that the ORS' deferral recommendations in this case are a departure from the accounting standards. (*Id.*) In fact, Mr. Payne noted that state commissions largely decide regulatory asset recovery on a case-by-case basis similar to our current practice. (Tr. Vol. 6, p. 1247-5). Witness Payne provided an overview of deferral accounting guidelines in Minnesota, Connecticut, New York, New Hampshire and Utah noting that the guidelines and recovery permitted varies by state. (*Id.* at 1247-5 – 1247-6.) At the hearing, Company witness Bateman testified that none of the states and authorities witness Payne cites in his surrebuttal testimony support the position that the ORS has taken in this case with respect to deferrals. (Tr. Vol. 3, p. 327.) In fact, in Minnesota, we identified a case where the Minnesota Public Utilities Commission allowed Xcel Energy to include the unamortized balance of its deferred nuclear-refueling outage costs in rate base and earn the overall allowed rate of return on that balance to "compensate the Company for the time value of money foregone as part of this deferred recovery." *See In re: Application of Northern States Power Company for Authority to Increase Rates for Electric Service*, Minnesota Public Utilities Commission, Docket No. E-002/GR-13-868 at 25 (May 8, 2015) (the "2015 Xcel Order").[41] We note that Mr. Payne did not

[41] In this case, the Minnesota Public Utilities Commission explained that the Company had been deferring and amortizing its nuclear-refueling-outage costs and that the commission "had approved this cost treatment to ensure greater accuracy in cost recovery by reasonably matching the time these costs are incurred with the time they are recovered while avoiding substantial fluctuations in those costs between rate cases." 2015 Xcel Order at 28. As discussed further below, this order also supports the Company's position that the appropriate amortization period should align with the period over which the costs were incurred.

address other states where deferrals and recovery of the type sought by the Company have been approved, such as Colorado,[42] Nevada,[43] New Jersey,[44] North Carolina,[45] Kentucky.[46] Upon review, this Commission finds it notable that North Carolina has allowed the types of returns requested by the Company in this case, during the deferral period and amortization period, as has this Commission in the past. (S*ee supra* note 37.)

In his surrebuttal testimony, Mr. Payne also argued that the Company uses deferral accounting as a vehicle to preserve the Company's ability to recover costs incurred outside the Test Period in its next rate case proceeding. Mr. Payne maintains that a utility should be granted deferrals for costs that meet a certain level of "extraordinary" in terms of circumstance and magnitude. (Tr. Vol. 6, p. 1247-7.) He offered that deferrals should be permitted for costs that

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[42] *See, e.g., Pub. Serv. Co. of Colo*., Decision No. C18-0762, P 18 (Colo. Pub. Utils. Comm'n Aug. 27, 2018) (granting Public Service Company of Colorado's request to establish a regulatory asset account for the incremental depreciation costs associated with the early retirement of two coal generating units and authorizing the Company to start earning a return on the regulatory asset at the utility's WACC rather than delaying decision until the Company's next base rate case in order to provide certainty to the utility and ensure customers receive the benefit of paying less on the regulatory assets than they otherwise would if the utility were not retiring the units early.)

[43] *Application of Nevada Power Company d/b/a NV Energy for Authority to Adjust its Annual Revenue Requirement*, 2017 Nev. PUC LEXIS 172 (December 29, 2017) (granting Nevada Power's request for rate base recognition and a six-year amortization period for the established voltage and volt-ampere reactive control and optimization project and Non-Standard Metering Option project regulatory assets, including corresponding carrying charges).

[44] *Re: Jersey Central Power & Light Company*, BPU Docket No. ER12111052 (Mar. 18, 2015) (finding that Jersey Central Power and Light Company's deferred O&M expenses associated with 2011 storm costs should be amortized over six over years with carrying costs on the unamortized balance).

[45] *Order Accepting Stipulation, Deciding Contested Issues and Requiring Revenue Reduction*, In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, et al., NCUC Docket No. E-7, Sub 1146, et al., 15-16, 66-67 (June 22, 2018) (allowing a return on deferred coal combustion residuals expenditures, and also authorizing a regulatory asset account to defer and amortize certain operations and maintenance expenses through amortization); *Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase*, In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, NCUC Docket No. E-2, Sub 1142 et al. (February 23, 2018) at 19 (allowing a return on unamortized balance of coal combustion residuals expenditures to be recovered over a five-year amortization period, subject to a management penalty of $30 million.)

[46] *The Application of Louisville Gas and Electric Company for Approval of Its 2004 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2004-00421 (Ky. PSC June 20, 2005) (allowing one-time ash transfer costs to be deferred and amortized over four years and authorizing the opportunity to earn a reasonable rate of return on the unamortized balance of the deferred costs in the environmental rate base).

are "non-recurring, unforeseen, and out of management's control" such as uninsured storm damage, losses for early plant retirements or environmental and regulatory remedies imposed by local, state or federal governments. (*Id.*) Citing the FERC Electric Chart of Accounts definition of "Extraordinary Items" as guidance,[47] he recommends that a threshold of approximately five percent of a utility's income, computed before extraordinary items, as an appropriate threshold for deferral consideration and he does not believe the Company's Customer Connect, GIP or installation of new AMI meters meets his proposed threshold. (*Id.*) Witness Payne argues that the Company's definition of deferred costs is overly broad and may allow the Company to continue to seek more deferrals for non-extraordinary O&M costs in the future and shift the risk of regulatory lag onto the customer. (*Id.* at 1247-8.) At the hearing, Company witness Bateman pointed out that all the deferrals at issue in this case have already been approved by the Commission. (Tr. Vol. 3, p. 327.) Furthermore, she testified that the authorities witness Payne cites, specifically, the FERC Electric Chart of Accounts and Deloitte Regulated Utilities Manual (*see* Tr. Vol. 6, p. 1247-7.), do not contain the criteria witness Payne cites for deferrals guidelines, namely, that the costs should be unforeseen or outside management control. (Tr. Vol. 3, p. 329.) In fact, the testified that the Deloitte Regulated Utilities Manual specifically lists rate case expenses as an example of a typical deferred cost. (*Id.*) Thus, she explained that rate case costs would not qualify for the criteria that Mr. Payne is proposing (that deferrals be unforeseen or outside of management control). (*Id.*)

At the hearing, Company witness Bateman testified that the guidelines recommended by witness Payne and criteria that should be applied for deferrals is more appropriate to discuss in a

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[47] We note that the FERC guidance witness Payne relies upon in the General Instructions concerns the Uniform System of Accounts definition of "Extraordinary Items" which had nothing to do with deferral accounting.

generic docket. (Tr. Vol. 3, p. 327.) In addition, she points out that all the deferrals at issue in this case have already been approved Commission. (*Id.*) Further, she explained that looking at other states to determine appropriate criteria for South Carolina is important, but should be done in the context of a generic docket and in a way that where the Commission can take into account whether those states might have other unique regulatory mechanisms such as future test years, multi-year rate plans, or multiple rides that may impact what are appropriate deferral criteria. (*Id.* at 327 - 328.) Thus, witness Bateman testified that this Commission needs to look at what criteria's appropriate for South Carolina given the regulatory framework in South Carolina, and that is more appropriately done in a generic docket. (*Id.* at 328.) We agree with witness Bateman.

Commission Conclusions on the Requested Treatment of Accounting Deferrals

During the hearing, the ORS and SCEUC implied that the Company's requests for deferral accounting orders is excessive. (*See* Tr. Vol. 6, p. 1252, 1255.) While it is true the Company has requested several deferrals over the past several years, it is also true that ORS has not contested any of them. (*Id.* at Vol. 6, p. 1240.) As explained by Company witness Bateman, customers have benefitted from the deferrals through the money spent for the underlying investment as well as the delays of and mitigation of rate increases. (Tr. Vol. 3, p. 331-32 (Company witness Bateman stating even just a five-month delay in the increase in rates [as a result of an approved deferral] benefits customers by anywhere from $10 to $20 million, depending on the increase ultimately approved by the Commission in the case).) As part of the Company's 2013 deferral petition, the ORS found value to customers in that benefit, contrary to the new position ORS witness Payne took in his surrebuttal testimony where he alleged that "only shareholders benefit from deferrals at the direct expense of customers." (*Id*. at 330-31.) Witness Payne acknowledges that the use of deferrals is a unique state consideration and that ultimately, public utility commissions, including this Commission, have wide-ranging discretion in making decisions on how deferrals should be addressed. (Tr. Vol. 6, p. 1244.) Mr. Payne also conceded that the use of deferral accounting could be impacted by any other regulatory mechanism which may be present in other states, such as the use of forward test years, alternative ratemaking, or riders which would otherwise allow recovery of costs not included in rates. (Tr. Vol. 6, p. 1285-86.) The Commission also notes that especially over the last decade, the electric utility industry has been encountering a period of intense capital investment needs driven by environmental compliance mandates, technological advances such as AMI, and efforts to strengthen utility infrastructure such as the Company's GIP to be addressed in a separate docket. Prior to 2016, the Company had not had a base rate case since 1988. As an alternative to requesting accounting orders for deferrals, the Company could instead choose to file rate cases more frequently. Rate cases are costly and require significant time and resource expenditures of the Company, Commission and ORS as well as other intervenors. In addition, we heard testimony from several public witnesses that were having difficulty paying their bills and are significantly impacted by the Company's requests to increase their rates. Rate stability is important to customers, especially low-income customers, who are struggling to pay their current electric bills. We must balance the interests of customers with ensuring the utility maintains its financial strength and ability to earn just and reasonable rates. Thus, we find that the Company's use of deferral accounting, where necessary, is an appropriate manner to address costs between rate cases. We also find that deferral accounting and recovery can be an appropriate way to mitigate the need for more frequent rate cases and rate shock for its customers. Further, we find that deferral accounting also mitigates the risk of degradation of the Company's earnings for certain types of costs incurred during periods for which the Company does not have a revised rates request pending. Deferral accounting may also be appropriate where there are new regulations that are not captured in current rates, or where the ratemaking formula may be inadequate to address the costs at issue. For example, deferral accounting can help bridge the gap for accounting effects from new technologies and unconventional investments that are not accorded Allowance for Funds Used for Construction ("AFUDC") accounting. A key consideration for the Commission would be whether any of the costs being deferred were included in the Company's rates to begin with. In any case, the time to address overall deferral policy should be on a prospective, not a retroactive basis. In fact, witness Payne admitted at hearing that the ORS deferral accounting recommendation in this case is a "relatively new policy" This policy has not been vetted through the generic docket sought by ORS. If the Commission is to change ratemaking policy in this state, it should be done in a more comprehensive fashion with the input of all utilities in this state and participation from stakeholders which would be affected.

Based on the evidence presented by the parties and our review of case law in other states[48] as explained above and below we continue to believe that the Company's deferred costs should be assessed for recovery on a case-by-case basis considering the unique facts of each case.

Based on the facts of this case and consistent with the basic regulatory premise that the Company should be permitted to earn a return on its prudent investment; we find it appropriate for the Company to earn a return on its prudently incurred deferred costs both during the deferral

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[48] *Investigation & Rulemaking Regarding When A Regulated Util. Should Be Permitted to Use Deferred Accounting Resulting in A Regulatory Asset or Liability*, 2014 Nev. PUC LEXIS 74 (March 27, 2014) (The Public Utilities Commission of Nevada ("PUCN") opened an investigation regarding when a regulated utility should be permitted to use deferred accounting resulting in a regulatory asset or liability, and whether the PUCN should establish a regulation regarding such issue. They concluded as follows: "Upon review of the information gathered in this investigation, the Commission has determined that promulgation of a regulation is not warranted at this time. **There is an overarching need for flexibility in dealing with unusual occurrences or events that may or may not reach some level of materiality…Addressing such matters on a case-by-case basis allows the Commission to revise its policy on regulatory assets/liabilities in response to changing conditions in the utility regulatory environment based upon new and/or updated information. It is a fluid process that does not necessarily lend itself to a regulation at this time**." (emphasis added)).

period and during the amortization period, particularly where amortization periods are lengthy. We are persuaded that there is a real cost to finance the Company's investments and a time value to money and thus it is fair for the Company to recover carrying costs on its deferred costs in order to both recoup the costs being deferred and the costs to defer them.[49] This decision in no way limits our evaluation on future deferrals or criteria to be established for consideration of deferrals requested in the future. ORS and SCEUC implied that the Company's request to recover a return on its deferred O&M costs through inclusion in rate base is inappropriate simply by virtue of the fact that through traditional ratemaking the Company does not earn a return on O&M expense incurred during the test year. (Tr. Vol. 6, p. 1260-61.) We find this argument completely misses the mark. The Company is not seeking deferral of certain O&M expenses just so it can later request a return to give those deferred O&M expenses some kind of "special status" (*see* Tr. Vol. 6, p. 1260.); rather, the Company is requesting deferrals to delay the need to file for a rate increase *which directly benefits customers*. Witness Payne himself concedes that the Company's rational for seeking the deferrals was to mitigate the rate impact to customers. (*Id.* at 1283.) Yet ORS and SCEUC fail to comprehend that the reason the Company has requested a return on these deferred O&M expenses is because there is a time value to money, money which the Company has fronted customers for prudent investments it made which were necessary to meet the Company's obligation to serve its customers. No party has disputed the prudency of the Company's deferred costs in this proceeding or the fact that the Company has incurred carrying

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[49] See In re: Petition of Jersey Central Power & Light for Review and Approval of Increases and Other Adjustments to its Rates and Charges for Electric Service and For Approval of Other Tariff Revisions*,* New Jersey Board of Public Utilities, Docket No. ER12111052 (March 18, 2015) at 57 ("The Board agrees with the Company that there should be a carrying charge on the O&M costs associated with the Major Storms included in this case because money has a time value that deserves to be recognized as a matter of fairness to investors. Non-recognition raises concerns in the financial community, particularly with the credit rating agencies.").

costs on the deferral; therefore, we conclude that permitting both a "return of" and a "return on" the Company's deferred costs in this proceeding is appropriate.

Also at dispute was the appropriate amortization period for a number of the Company's deferrals. The differences between the Company's proposals and ORS' recommendations are as follows:

		Deferred Balance ($MM)	**Length of Amortization in years**	
Adj #	**Adjustment**	**Company Position**	**Company Position**	**ORS Position**
SC -1700	Harris COLA	$6.7	5	8
SC -1900	SC AMI	$1.6	3	15
SC -3500	SC Grid	$2.2	2	5

Company witness Bateman testified that while amortization periods are subjective, there should be a balance and consideration between the impact on customer rates and the impact on the Company's cash flow. (Tr. Vol. 3, p. 326-11.) In addition, witness Bateman points out that in the Company's last rate case, the Company agreed to delay beginning the amortization on both the Harris COLA and Fukushima/Cybersecurity deferred balances. (*Id.*) In this case, the ORS recommends an 8-year amortization for the Harris COLA because that is the length of time over which the costs were incurred. However, witness Bateman explains that absent the settlement agreement in the last case, the Company would have already begun amortizing these costs as of January 1, 2017. (*Id.* at 326-12; 332.) Had the Company used an eight-year period to amortize the costs at that point, there would only be five and a half years remaining in the amortization period by the time new rates are effective in this case. (*Id.*) Therefore, she states, the Company's proposed amortization period is more appropriate even using the ORS' logic. (*Id.*) She further explained that since the ORS has recommended to disallow the return during the amortization period on a portion of all the Company's deferred balances, the longer amortization periods proposed by Mr. Payne exacerbate the disallowance. (*Id.*)

We agree with Company witness Bateman. As previously noted, there is a time value to money and the amortization periods recommended by the ORS are unreasonably long. We continue to find that "[t]he selection of the proper amortization period is a matter of judgment, involving a number of factors." *In Re: Application of Piedmont Natural Gas Company for An Adjustment of its Rates and Charges and for Approval of Revised Depreciation Rates,* PSCSC Docket No. 2002-63-G, Order No. 2002-761 at 25. In the past we have looked at the average period between rate cases to guide us in determining an appropriate amortization period for deferred costs. (*Id.* at 40-41 (finding five years to be an appropriate amortization period for deferred environmental costs based on the average time between the utility's past four rate cases) *citing Order No. 9, Re: Matanuska Telephone Association, Inc.*, Regulatory Comm'n of Alaska, Docket No. U-00-28 at 7- (Nov. 29, 2000) ("A utility should be allowed to recover the best estimate of its expense on a prospective basis. The amortization period should reflect the best estimate of when the utility will file its next rate case. The amortization and recovery of expense should be matched with the most reasonable estimate of the benefit associated with the expense; that is the number of years between rate cases."). Given the fact that the Company's last rate case was two years ago and based upon the fact that the Company is requesting additional deferrals for which it will likely seek recovery in rates in a future rate case, we find that the Company's proposed amortization periods in this case are more appropriate. We have also considered the accumulation period of the costs in determining a reasonable amortization period. (*In re: Application of South Carolina Electric & Gas Company for Adjustments in the Company's Electric Rate Schedules and Tariffs,* Docket No. 2004-178-E, PSCSC Order No. 2005-2 (January 6, 2005) at 63-64 ("We agree with the Company and Staff that it is reasonable to allow an amortization period that matches the accumulation period yet spreads the impact of the cost in a reasonable way"). While the ORS' recommended amortization period for the Harris COLA costs matches the accumulation period, we also consider the fact that the Company agreed to delay its recovery of the Harris COLA costs in that case and find that the five-year period proposed by the Company is appropriate and approved. For the aforementioned reasons, we approve the Company's proposed amortization periods as presented in the table above.

We also find it appropriate to grant an accounting order for the Company's requested accounting deferrals in this case to 1) continue the deferral for coal ash basin closure compliance costs after the cut-off date for this rate case of December 31, 2018; 2) establish a regulatory asset at the time of the Asheville plant's retirement for the remaining net book value, and permission to defer to this regulatory asset any costs related to obsolete inventory, net of salvage, at the time of retirement, 3) continue the deferral for ongoing costs incurred in connection with deployment of AMI in service after December 31, 2018, and 4) approve deferral of the Company's on-going Grid Improvement costs. We permit the Company to also defer the carrying charge on its investment as well as the carrying charge on the deferred costs at its WACC approved in this case during the deferral period. In addition, we also find it appropriate to approve the Company's request to continue deferral of the two 2014 Storms and Hurricane Matthew costs after the rates effective date in this case at the overall weighted average cost of capital approved in this case. This Order will not preclude the Commission from addressing the reasonableness of the costs deferred in the regulatory asset account in a future general rate proceeding.

Adjustment #17 – Harris COLA, GridSouth, Fukushima/Cybersecurity, 2014 Storm Costs

DE Progress has deferred into regulatory asset accounts costs incurred from the suspension of its Harris COLA review with the NRC, costs related to compliance with the NRC requirements in response to events at Fukushima in March 2011 and NRC requirements related to cybersecurity, GridSouth RTO costs, and costs related to extreme storm events in 2014. The deferral begins amortization for three different deferred balances and addresses a fourth deferred balance all of which existed at the time of the Company's last South Carolina general rate case, but of which the Company chose not to begin amortization at that time in order to mitigate the customer rate impacts. (Tr. Vol. 3, p, 320-19.) The Company proposes to adjust depreciation and amortization expense by $3,186,000, income taxes by ($795,000) (Hearing Ex. 17 (Bateman Rebuttal Exhibit 1, p. 3), working capital investment by ($15,744,000) (Bateman Rebuttal Exhibit 1, p. 3), and accumulated deferred taxes by $3,928,000 (Hearing Ex. 17 (Bateman Rebuttal Exhibit 1, p. 4) and is seeking recovery of these deferred costs over a five-year period. ORS proposed to adjust depreciation and amortization expense by $2,634,000, income taxes by ($657,000), working capital investment by ($23,118,000), and accumulated deferred taxes by $5,768,000. (Tr. Vol. 6, p. 1245-5.)

Harris COLA

In Order No. 2014-138 in Docket No. 2013-472-E, the Company requested, and the Commission approved, deferral of costs related to the Harris Units 2 and 3 COLA.[50] This adjustment amortizes the South Carolina retail deferred balance of $6.7 million over a 5-year period. (Tr. Vol. 3, p, 320-19.) The Company has not proposed to include the unamortized balance

[50] The Shearon Harris Units 2 and 3 COLA remains in suspended review status at the NRC and DE Progress is considering withdrawal.

of the Harris COLA deferral in rate base. (Tr. Vol. 6, p. 1245-6.) ORS agrees with the deferral balance of $6.7 million and proposal to exclude unamortized balance from rate base but is recommending an eight-year amortization period for the Harris COLA deferral to match the cost recovery period with the cost accumulation period. (*Id.*)

Fukushima/Cybersecurity

Also, in Order No. 2014-138 in Docket No. 2013-472-E, the Company requested and the Commission approved deferral of costs related to compliance with NRC requirements in response to events at Fukushima in Japan in March 2011 and NRC requirements related to cybersecurity. This adjustment amortizes the South Carolina retail deferred balance of $5.5 million over a 5-year period. (Tr. Vol. 3, p, 320-19.)

According to ORS, the Company provided ORS with support for a Fukushima/Cybersecurity deferral balance of $5,541,000, consisting of a December 31, 2017 balance of $4,729,000, actual costs to defer during the 2018 year of $324,000, projected costs to defer between January 1, 2019 to May 30, 2019 of $242,000, and a 2018 correction to the 2017 balance of $246,000. (Tr. Vol. 6, p. 1245-7.) The Company's application per book rate base includes the $4,729,000 December 31, 2017 deferral balance. (*Id.*) The Company proposes to include the additional deferred amounts, less one full year of amortization in rate base. (*Id.*)

ORS proposes a Fukushima/Cybersecurity deferral balance of $5,299,000 which will provide the Company a recovery of actual deferred costs as of December 31, 2018 including the 2018 correction to the 2017 balance. (*Id.*) ORS recommends the Commission approve the five-year amortization period for the deferral balance proposed by the Company but does not recommend the deferral balance include projected costs because projected costs are not known and measurable. (*Id.*) ORS recommends the December 31, 2017 deferral balance be removed from the Company's rate base since the balance consists of deferred O&M expense. (*Id.*) Likewise, ORS recommends the remaining deferral balance be excluded from rate base because it consists of deferred O&M expense. (*Id.*) ORS' argues that its recommendation to remove and exclude the actual deferred O&M expense from rate base is consistent with regulatory accounting practices for operating-related costs. (*Id.*) ORS believes that its recommendation allows the Company to recover its actual deferred costs through amortization of the proposed deferral balance which is a sufficient level of cost recovery. (*Id.*) If the Company is allowed to include deferred O&M expenses in rate base, ORS explained that the Company will earn a return on its O&M expenses. (*Id.*)

<u>GridSouth RTO</u>

In Docket No. 2001-139-E, the Company, along with other utilities in the state, filed a notice of application to form an RTO, GridSouth, and then filed a notice withdrawing the application. The associated deferred costs have been included in the Company's rate base since that time. (Tr. Vol. 3, p. 320-20.) The Company's adjustment amortizes the South Carolina retail deferred balance of $3.7 million over a 5-year period. (*Id.*)

ORS agrees with the proposed deferral balance of $3,676,000, and the Company's proposed five-year amortization period. (Tr. Vol. 6, p. 1245-8.) However, ORS recommends removing the deferral balance from the Company's rate base as the costs are not capital expenditures. (*Id.*) ORS argues that its recommendation to remove the deferred expenses from rate base is consistent with regulatory accounting practices for operating-related costs and its recommendation allows the Company to recover its actual deferred costs through amortization of the proposed deferral balance which is a sufficient level of cost recovery. (*Id.*) ORS explains that if the Company is allowed to include deferred non-capital expenses in rate base, the Company will earn a return on non-capital expenses in excess of what it has already earned since its last general rate case. (*Id.*)

<u>2014 Storms</u>

In Docket No. 2014-482-E, the Company requested, and the Commission approved, deferral of costs related to extreme storm events in the first quarter of 2014. (Tr. Vol. 3, p. 320-20.) This adjustment removes the South Carolina retail deferred balance from rate base. (*Id.*) ORS agrees with the Company's proposed treatment to remove the deferral balance from rate base. (Tr. Vol. 6, p. 1245-9.) As noted previously, this 2014 storms deferral request was addressed separately by the Commission in Order No. 2019-126 in Docket No. 2019-26-E. ORS witness Payne testified that ORS reserves its rights to address the reasonableness of the costs deferred in the regulatory asset account in the next general rate proceeding. (*Id.*)

<u>Conclusion</u>

For the reasons discussed above where we rejected the ORS' proposed deferral accounting recommendation, we find it appropriate to approve the Company's request to recover its deferred costs for the Harris COLA, Fukushima/cybersecurity, and GridSouth as presented in Hearing Ex. 17 (Bateman Rebuttal Exhibit 1) over a five-year amortization period. We also find that the projected Fukushima/Cybersecurity costs are reasonably calculated and are known and measurable. *See Hamm v. S.C. Pub. Serv. Comm'n*, 309 S.C. 282 (1992) ("Such adjustments are within the discretion of the Commission and, although they must be known and measurable within a degree of reasonable certainty, absolute precision is not required."). Furthermore, the Commission finds and concludes that the Company's request to recover the regulatory assets for the Fukushima/Cybersecurity and GridSouth deferrals over a five-year period, including the after-tax return on the unamortized balance, is just and reasonable to all Parties in light of the evidence presented.

Adjustment #19 – Amortize deferred cost balance related to AMI

The evidence in support of the findings of fact is found in the verified Application, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

In its Application, the Company requested recovery of its deferred costs,[51] plus a net of tax return on the unamortized balance for three years, associated with the deployment of AMI across the DE Progress system. (Application at 10.) The Company also requested permission to establish a regulatory asset/liability and defer to this account the incremental O&M and depreciation expense for AMI meters installed after December 31, 2018, including the carrying charge on the investment and on the deferred costs at the weighted average cost of capital approved in this case. (Application at 24.) Company witness Don Schneider, Jr. testified about the Company's deployment of AMI.

Witness Schneider explains that AMI is the term used to refer to a comprehensive metering solution – including meters, communication devices, communication networks, and back office systems – used to create two-way communications between customer meters and the utility. (Tr. Vol. 3, p. 437-4.) It is an overall metering solution, as opposed to just a new type of meter, which allows for remote meter reading, eliminating walk-by and/or drive-by meter reading. (*Id*. at 473-5.) AMI meters are digital electricity meters that have advanced features and capabilities beyond traditional electric meters. (*Id*. at 473-4.) Some of the advanced features include the capability

[51] In Docket No. 2018-205-E, the Company petitioned for approval to defer into a regulatory asset account incremental operating and maintenance expense and depreciation expense incurred once the AMI meters were installed, as well as the associated carrying costs on the investments and deferred costs at its weighted average cost of capital. The Commission approved the Company's petition on August 9, 2018 in Order No. 2018-553 (2018).

for two-way communications, interval usage measurement, tamper detection, voltage and reactive power measurement, and net metering capability. (*Id.*) Witness Schneider stated, as of September 30, 2018, DE Progress installed approximately 38,000 smart meters in its South Carolina service territory and plans to continue AMI implementation through early 2020 for the remaining approximately 128,000 meters. (*Id.* at 473-8.) Witness Schneider further explains that for customers who do not wish to have a smart meter, the Commission approved an opt-out provision contained in the Meter Related Optional Programs Rider MROP as an alternative solution made available to the customer. (*Id.* at 473-9.)

According to witness Schneider, benefits of AMI include allowing customers access to more detailed usage information (down to the hour) via the Duke Energy online customer portal. (*Id.* at 473-5.) Further, regular meter reads and off-cycle meter reads (for the purpose of transferring service) can be performed remotely for customers, eliminating the need for a technician to come to the customer's premise. (*Id.*) Additionally, service connections and disconnections can be performed remotely for the majority of customers who are starting and/or stopping service, again, eliminating the need for a technician to come to the customer's premise. (*Id.*) During storm outages, damage assessment and repair verification can be done much more quickly when customers have a smart meter by interrogating, or "pinging", the meter to determine if it is functioning. (*Id.*) Witness Schneider further stated that with the capability to record interval usage data, smart meters are a foundational technology that can enable new rate designs and, combined with the new Customer Connect system, will lead to expanded options and flexibility in supporting enhanced customer services and programs. (*Id.* at 473-11.) He also testified that the Company expects to experience operational savings in the form of costs it otherwise would have incurred but for the deployment of AMI, resulting from an increase in remote customer order fulfillment and reduced manual and drive-by meter reading costs. (Tr. Vol. 4, p. 503-04.)

Witness Schneider also explained that the Company's deployment of AMI has enabled new programs to become available to DE Progress customers with smart meters, including: (1) Pick Your Due Date, which allows eligible customers to select their desired billing due date from the 1st to the 31st of the month, better aligning with customers' needs; and (2) Usage Alerts, which provides eligible customers with an alert at the midpoint of their billing cycle. (Tr. Vol. 3, at p. 473-12.) Further, the Company plans to launch a Prepaid Advantage program pilot in its service territory, similar to the Prepaid Advantage Program approved by the Commission for DE Carolinas in Docket No. 2015-136-E. (*Id.* at 473-13.) The Company expects this program will allow customers greater payment flexibility, allowing frequent payments which may help customers better manage their finances.[52] (*Id.*)

No party contested the prudency of the Company's investment in AMI. However, ORS recommended the deferred cost of capital portion of the deferral balance be included in rate base but not the deferred depreciation and O&M expense portion of the deferral balance. (Tr. Vol. 6, p. 1245-11 – 1245-12.) The ORS also recommends recovery of the deferral balance over a 15-year amortization period.

Upon consideration of the evidence in this proceeding, the Commission finds and concludes it appropriate to approve the Company's request to recover its deferred cost balance related to the deployment of AMI across its service territory, plus a net of tax return on the

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[52] The Company's Prepaid Advantage program is addressed in Findings and Conclusions No. 56.

unamortized balance for three years.[53] The Commission also finds and concludes it appropriate to approve the Company's request for an ongoing deferral for AMI meters installed after December 31, 2018. In arriving at its decision, the Commissio

n is persuaded that the value and benefits associated with AMI are appropriate and warrant recovery from South Carolina customers. Further, the Commission rejects the ORS' deferral accounting treatment recommendation for the reasons previously discussed and finds the recommendation for a 15-year amortization period is unreasonably long and does not allow the Company to appropriately recover the cost of its prudent investment. The Commission further finds and concludes that the Company shall report annually to the Commission the operational savings associated with AMI deployment in South Carolina for a period of two years or until the Company's next rate case, whichever is later. The filing of the report shall commence upon the full deployment of AMI in the DE Progress service territory, or for the 2020 reporting year, whichever is sooner.

D. Other Disputed Adjustments

Adjustment #22 – Normalize O&M labor expenses

In her direct testimony, DE Progress witness Bateman testified that the Company adjusted wages and salaries, and related employee benefit costs, to reflect annual levels of costs as of July 1, 2018. (Tr. Vol. 3, p. 320-24.) This adjustment also reflects changes in related payroll taxes. (*Id.*)

[53] The Commission's decision to approve recovery of the Company's deferred AMI costs correlates with the Commission's conclusions regarding whether the Company is entitled to earn a return on deferred capital and operating expenses as addressed earlier in this section in the discussion on deferrals.

The ORS made two recommendations with respect to this adjustment, one controverted and one not controverted. The uncontested recommendation made by the ORS was to update the salary allocator for the Company's wages and salaries and related employee benefit costs to the same date as the O&M labor expense, July 1, 2018, to which the Company agreed. (Tr. Vol. 6, p. 1236-10; Tr. Vol. 3, p. 326-15.)

The contested component of this adjustment relates to compensation the Company pays to its employees, and, in particular, a portion of employee compensation represented by incentive pay. ORS persists in characterizing the Company's carefully designed incentive pay program as a "bonus" despite uncontroverted testimony from the only human resources professional who testified that it is *not* a "bonus" (*see* Tr. Vol. 4, p. 651); rather, it is "part of … each employee's market competitive pay." (*Id.*) As detailed more fully below, the Commission agrees that ORS' insistence on calling the program a "bonus" program is, at best, misleading. But however characterized, the merits of the ORS proposal are deeply troubling.

ORS recommends removal of $4,172,000-worth of employee compensation, consisting of 50% of STI compensation and LTI compensation for all qualifying employees. [54] For the reasons set forth herein, the Commission disagrees with this recommended disallowance. No party takes issue with the Company's overall compensation levels. It follows, therefore, that incentive

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[54] There is an obvious mathematical error embedded in the ORS recommendation. Hearing Exhibit 26 shows the ORS' calculation of its proposed disallowance by category of Company employee. The largest number of employees (over 29,000) is in the category "All Other." ORS proposes to disallow 50% of this pay, even though for this category only 30% of the incentive compensation is tied to the supposedly shareholder-focused metrics to which ORS objects. Thus, ORS' proposed disallowance is overstated by $1,280,000 for the over 29,000 rank-and-file Company employees, and overstated by $1,590,000 for all employees. Even were the Commission to countenance disallowing any of the employees' incentive pay – which it is not – it is distressing that mathematical errors of this magnitude persist in ORS' recommendations.

compensation, which is merely a portion of overall employee compensation expense, is a prudently incurred cost of service.

ORS is certainly familiar with this concept, in that it uses the National Association of Regulatory Utility Commissioners' *Electricity Utility Cost Allocation Manual* ("NARUC Manual"), of which the Commission has taken judicial notice. (Tr. Vol. 6 p. 1286 - 1287.) The NARUC Manual states:

> A utility, in order to remain viable, must be given the opportunity to recover its prudently incurred total cost of providing electric service to its various classes of customers. Cost of service is usually defined to include all of a utility's operating expenses plus a reasonable return on its investment devoted to the service of the rate paying public.

(*Id*. at 1288.) This is in fact the law. *See*, *e.g.*, *Southern Bell Tel. & Tel. Co. v. Pub. Serv. Comm'n*, 270 S.C. 590, 608-09 (1978) (Ness, J concurring and dissenting). As explained in more detail below, no party, including ORS, has provided the Commission with any justification to disallow this prudently incurred cost. Further, were the Commission to disallow this prudently incurred cost, then the disallowance would necessarily negatively impact the Company's opportunity to earn a fair and reasonable return on the investments made by the Company in providing utility service to its customers. Neither result is permitted by the law.

In his direct testimony, ORS witness Major sought to justify his $4 million proposed incentive compensation adjustment with a scant handful of words. He states that the 50% disallowance is based solely on the incentives "being attributable to Company earnings." (Tr. Vol. 6, p. 1236-11.) His surrebuttal testimony makes clear that this is mere supposition on the part of ORS, in that he says "***If*** employees are largely driven by stock performance rather than the service to customers …" then the disallowance can be justified, premised on some notion of "sharing" between the Company and its customers. (*Id.* at 1238-4 (emphasis added).) However, ORS has presented no evidence supporting this "if."

ORS witness Major is an auditor, not a human resources professional, a field in which he indicated he was not "versed." (*Id.* at 1271.) Company witness Metzler, by contrast, *is* a human resources professional, with expertise in designing compensation programs to drive customer-focused behavior. She explained the Company's overall compensation philosophy is to target total compensation of base pay and incentives at the median of the market when compared to peer companies. (Tr. Vol. 4, p. 641–42.) According to witness Metzler, contrary to the ORS' supposition, employee compensation and incentives tied to metrics such as Earnings Per Share ("EPS") and Total Shareholder Return ("TSR") benefit customers because those metrics reflect how employees' contributions translate into overall financial performance. (*Id.* at 643.) EPS, for example, is a measure of the Company's performance, and that performance is reflective of how certain goals – safety, individual performance, team performance, and customer satisfaction (all of which are components of incentive pay) – are met in a cost-effective way. (*Id.*) Divorcing employee performance from such an important measure of a rate-regulated company's overall health is unreasonable and counterproductive. (*Id.*) Additionally, witness Metzler explained that in order to attract a well-qualified and well-led workforce, the Company must compete in the marketplace to obtain the services of these employees. (*Id.* at 642.) The recommended adjustments would render the Company's compensation uncompetitive with the market, which would result in the inability to attract and retain the talent the Company needs to run a safe and reliable electric system. (*Id.*) Finally, witness Metzler pointed out that no witness in this proceeding challenges the reasonableness of the level of compensation expenses reflected in the ratemaking test period for the Company. (*Id.*) Nor has anyone challenged that the compensation and benefit programs are necessary and critical in their entirety for attracting, engaging, retaining, and directing the efforts of employees with the skills and experience necessary to safely, efficiently, and effectively provide electric services to DE Progress customers. (*Id.* at 642-43.)

The undisputed evidence in this case shows, consistent with witness Metzler's testimony, that alleged "divergence" between the customer interest and the Company or shareholder interest does not in fact exist. Company witness Ghartey-Tagoe testified that part of his compensation is incentive based:

> [T]o the extent that I work hard to reduce costs, I actually turn out well because the earnings will be better. And that's why [it] … baffles me that the ORS would think earnings per share is a shareholder-focused metric, when, in fact, reducing costs, keeping costs low is directly related to the cost that our customers bear.

(Tr. Vol. 3 p. 382.) Specific testimony from Company witnesses shows how this works in practice. For example, witness Sullivan noted that over the past 2½ years the Company's cost of debt had remained essentially flat even in a generally rising interest rate environment. (Tr. Vol. 5-2, p. 980-981.) He indicated that while the Company is undertaking a large capital investment program, its cost-effective capital raising methods keep capital costs as low as possible – thus benefiting customers with "virtually constant" borrowing rates "during a period of volatility and, in fact, rising longer-term interest rates …." (*Id.* at 981.) And, he concluded, this was not an "either/or" proposition – either good credit quality or low rates, but not both: "I think … good credit quality and reasonable consumer prices can co-exist. It's not one versus the other … but, rather, if we're managing our costs as carefully as we can … I believe we can try to accomplish both." (*Id.* at 980.)

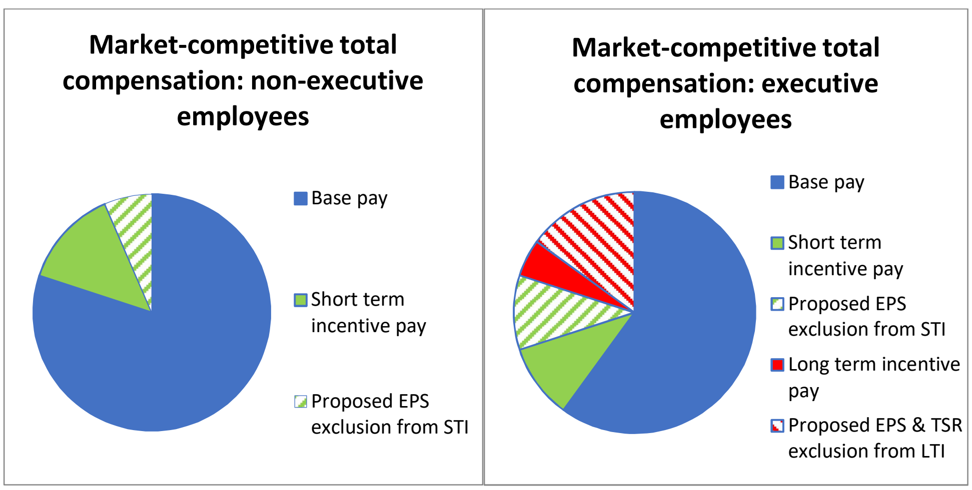
ORS witness Major actually agrees with the Company's position. He acknowledged that downward pressure on the Company's expenses could be beneficial to both shareholders (in that

that aids higher earnings per share) *and* customers (in that that leads to rates lower than they otherwise might be). (Tr. Vol. 6 p. 1266 – 1267.) He conceded particularly that rank-and-file employees can *both* benefit customers and positively impact the Company's earnings. Thus, witness Major indicated that he "would imagine" that when a lineman restores power after a hurricane, that benefits both customers and earnings. (*Id*. at 1268.) He agreed that a customer service representative who assists customers struggling to pay bills would benefit both customers and the Company's earnings. (*Id*. at 1270.) He acknowledged that a plant engineer who came up with a process to save time and money without compromising safety would benefit both customers and earnings. (*Id*. at 1271.) Yet in each instance witness Major insisted that customers and the Company should share 50/50 that component of the employees' overall compensation that is composed of incentive pay.

Having effectively conceded that its supposed customer/shareholder dichotomy is without foundation, ORS turns to a number of other justifications to attempt to support its proposed incentive compensation disallowance. None of ORS' justifications have any merit.

First, ORS witness Major states, citing this Commission's Order No. 2012-951, that allowing recovery of that portion of incentive compensation that is based upon EPS measures would be a "***vast departure*** from this Commission's previous decisions on this issue." (*Id.* at 1238-5 (emphasis added).) But Order No. 2012-951 reflected the Commission's approval of a settlement between the utility and most of the other parties to a rate proceeding that resulted, *inter alia*, in the utility agreeing to reduce its cost of service by an amount equal to 50% of incentive compensation tied to EPS measures. Nowhere in that Order does the Commission make any finding that it would be appropriate in a non-settlement context to disallow this expense, assuming that it was a prudently incurred expense (as is the case here). ORS' reliance upon Order No 2012-951 is therefore wholly misplaced, and ORS witness Major's invocation of that Order in this non-settlement context is completely inapposite. The Commission rejects the notion that Order 2012-951 may be used by ORS in this fashion.

Second, ORS resorts to sleight of hand, by repeatedly characterizing the incentive components of the Company's compensation program as "bonuses" (*see*, *e.g.*, Tr. Vol. 3, p. 239), ORS apparently seeks to have this Commission infer that the incentive components are something on top of market-competitive compensation. Rather, as witness Metzler demonstrates, incentive compensation is a part of overall compensation, the sum total of which is designed to be at the median of the market and, therefore, market-competitive. This is shown by Figures 3 and 4 from witness Metzler's testimony:



(Tr. Vol. 4, p. 645-9.) As she states, "[R]emoving either of the cross-hatched pie pieces, representing the portions of compensation that the ORS wishes to exclude from rates, would leave the compensation at a below-median level" (*Id*., p. 645-8.) Base pay of the Company's employees is likewise only a component of total market-based compensation. (*See*, *e.g.*, *id*. at 674 ("[W]ithout the incentive pay, we would need to roll that amount of compensation into their base pay in order for their pay to remain competitive.") For the Company's compensation levels to fall below competitive levels would be to the ultimate detriment of customers. To the extent that ORS seeks to convey the impression through its use of the term "bonus" that base pay alone equals market competitive pay and incentive pay/bonus is an extra over and above market competitive pay, the evidence is to the contrary.

Ultimately, ORS relies upon the concept of "equitable sharing" of incentive compensation. Again and again in his live testimony ORS witness Major invoked this concept in seeking to justify ORS' position. *(See*, *e.g.*, Tr. Vol. 6, p. 1268 ("a 50-50 split equitably distributes costs between the Company and its customers"); *Id.* at 1269 ("customers should not bear the entirety of the cost"); *Id.* at 1270 (ORS position would "distribute that equally amongst customers and the Company").) As he concluded, ORS is "not disagreeing with the Company's total compensation program … we just feel like … [a] fair and equitable allocation needs to exist." (*Id*. at 1273.) The problem here is twofold. First, ORS' selection of a 50% disallowance is completely arbitrary. There is no evidence – none – that supports a disallowance at that level. ORS simply assumed that there was a divergence between the Company's shareholders and its customers somehow related to the Company's choice to put some portion of its employees' compensation at risk, with some part of the at-risk portion tied to the Company's financial performance through measures such as EPS. This is a false premise – there is no such divergence, and certainly no evidence proffered by ORS showing the existence of any such divergence. The evidence is in fact to the contrary, as ORS itself concedes.

Second, and more fundamentally, ORS' "equitable sharing" concept has no support whatsoever in the law. As the NARUC Manual makes clear, a public utility is entitled to the opportunity to recover its prudently incurred cost of service, with cost of service "defined to include *all* of a utility's operating expenses …." (*Id*. at 1288 (emphasis added).) There is no legal basis that would allow the Commission to force the Company to "share" in the burden of reasonable and prudently incurred costs related to the provision of electric service to its customers. To the contrary, such "sharing," particularly in an arbitrary amount, serves only to make it impossible for the Company to earn the return required under *Hope* and *Bluefield*. *See Potomac Elec. Power Co. v. Pub. Serv. Comm'n*, 380 A.2d 126, 131 (D.C. 1977) (citing *Fed. Power Comm'n v. Natural Gas Pipeline Co*., 315 U.S. 575, 585-86 (1942); *McCardle v. Indianapolis Water Co*., 272 U.S. 400, 408 (1926); *Bluefield,* 262 U.S. 679, 690) (The U.S. Supreme Court held that "rates which are not adequate to yield a reasonable return on the value of the property used by a utility company to furnish its service to the public are unjust, unreasonable, and confiscatory, and that their effectuation would deprive the utility of its property without due process or just compensation.").

ORS concedes that the incentive compensation issue is not one of total compensation paid to the Company's employees. (Tr. Vol. 6, p. 1273.) In other words, ORS concedes that the aggregate level of compensation paid to the Company's employees is reasonable and prudent. Indeed, under our law, the Company's "expenses are presumed to be reasonable and incurred in good faith" unless challenged. *Hamm v. South Carolina Public Service Comm'n*, 309 S.C. 282, 286 (1992) (internal citations omitted). But, if challenged, the challenge must be with facts, available to be gleaned through the "liberal discovery provisions" permitted to ORS. *Id*. Here, ORS has presented no facts, only a premise – that there is some sort of divergence between the customer interest and the shareholder interest embedded in the Company's incentive compensation program – that in truth is a false premise.

The Commission rejects ORS' false premise, and rejects ORS' proposed $4,172,000 employee compensation disallowance.

Adjustment #29 – Adjust O&M for executive compensation

In her direct testimony, Company witness Bateman testified that the Company has made an adjustment to remove 50 percent of the compensation of the four Duke Energy executives with the highest level of compensation allocated to DE Progress in the Test Period. (Tr. Vol. 3, p. 320-26.) This adjustment amounts to a reduction in O&M expense by ($304,000) and income taxes by ($76,000). (Hearing Ex. 17 (Bateman Rebuttal Ex. 1, p. 3.) She explained that while the Company believes these costs are reasonable, prudent, and appropriate to recover from customers, DE Progress, for purposes of this case, agrees to make an adjustment to this item. (Tr. Vol. 4, p. 320-26.) The ORS agrees with the Company's exclusion of 50 percent of the compensation for the top four executives; however, because ORS witness Major has proposed to remove 50 percent of incentives for *all* employees via Adjustment #22, he added back the 50 percent of incentives for the top four executives in Adjustment #29 so as not to double count. (*See* Tr. Vol. 6, p. 1236-13.) Because, as discussed above, the Commission agrees with the Company that it is inappropriate to disallow a portion of STI and LTI program costs as recommended by the ORS, the Commission finds that the Company's original adjustment to exclude 50 percent of compensation, including incentives, for its top four executives (Adjustment #29) is appropriate and that there is no need to change this adjustment to reflect the ORS' recommendation with respect to Adjustment #22. The Commission finds this adjustment reasonable and appropriate to address the concerns raised about executive compensation at the public hearings.

Adjustment #30 – Adjust for Customer Connect Project

In its Application, the Company requested recovery of its deferred costs[55] and approval to include approximately $1.4 million annually for ongoing O&M expenses associated with replacing the Company's current CIS with Customer Connect. (Application at 9; Tr. Vol. 3, p. 482-19.) Company witness Hunsicker testified about Customer Connect and the costs and revenue requirement the Company is seeking in this case to support this project. (Tr. Vol. 3, p, 482-7 – 482-19.) Witness Hunsicker explained the Company's current CIS was developed over thirty years ago, and was not designed to efficiently support new capabilities. (*Id*. at 482-4 – 482-5.) She stated the Company and its customers' needs are very different than they were when the original CIS was constructed, and the system is past the point where modular "bolt on" systems or modular upgrades are effective. (*Id*. at 482-5 – 482-7.) Additionally, the Company's current CIS has many deficiencies. For example, the Company's existing CIS is not equipped to handle complex billing arrangements, such as net metering for self-generating customers, and these bills must be manually calculated. (*Id*. at 482-5.) The current CIS also does not enable access to account histories nor does it allow customers to employ preferred communication methods. (*Id*. at 482-6.) Witness Hunsicker explained that the new CIS will provide a universal and simplified process for customers, improve billing, enable a new billing format, allow the Company to easily identify and implement new rate structures for customers, and interface with the Company's new AMI technology. (*Id*. at 482-10.) Witness Hunsicker explained that Customer Connect began analysis and design in January 2018, and is currently planned to be in-service for DE Progress in

[55] In Docket No. 2018-205-E, the Company petitioned for approval to defer into a regulatory asset account the incremental O&M expense associated with the deployment of Customer Connect. The Commission approved the Company's petition on August 9, 2018 in Order No. 2018-553 (2018).

2022. (*Id*. at 480.) She further explained that the implementation will be phased and that new capabilities will be available to customers each year leading up to full deployment. (*Id*. at 482-13 – 482-16.) In fact, Ms. Hunsicker testified that the Company started delivering benefits to customers in June 2018, by leveraging data behind the scenes to serve its customers in different ways. (*Id*. at 482-13.) The estimated costs for Customer Connect for DE Progress, South Carolina, is between \$20 and \$25 million, which is based on executed fixed price contracts for the primary software (SAP), systems integration (Accenture) and change management professional services (Ernst and Young), following an extensive request for proposal process conducted in 2016. (*Id*. at 482-16.)

Witness Hunsicker stated that due to the nature of the project costs, a significant amount of the spending between the test year and the in-service date will be O&M expenses. (*Id.* at 482-19.) Accordingly, witness Hunsicker explained that Company witness Bateman includes a pro-forma adjustment in her testimony that increases the test year O&M expense associated with the project from approximately \$0.2 million to \$1.4 million. (*Id.*) This increased amount is the average expected annual O&M expense associated with the project, from 2019 through 2020. (*Id.*) Witness Hunsicker also explained that witness Bateman seeks to amortize the deferred balance of O&M expenses incurred by the Company since January 1, 2018, approved by the Commission in Order No. 2018-553. (*Id.*)

While no party contested the value or benefits to customers associated with the Customer Connect program, ORS witness Payne testified in response to the Company's request for approval to increase the test year O&M expense for Customer Connect deployment. In his direct testimony, witness Payne recommended an adjustment removing the projected two-year average O&M expense of approximately \$1.2 million for the Customer Connect program from the Company's pro forma because, he argues, the expenses are not known and measurable. (Tr. Vol. 6, p, 1245-12.) According to witness Payne, the Company recorded $160,000 in actual O&M expense during the test year attributed to the Customer Connect project and ORS recommends approval of only these expenses. (*Id*. at 1245-13.)

In her rebuttal testimony, Company witness Hunsicker stated the Company does not agree with the ORS' recommendation because the expenses correlate to the underlying fixed contracts with its vendors, and are therefore "known," because the Company has entered into fixed contracts with multiple vendors to develop the program, and the contracts contain provisions requiring the Company to provide specified levels of internal labor to support execution of the work; and "measurable," because the fixed contracts contain specified price terms, which serve as the basis for the Company's forecasted expenses. (Tr. Vol. 3, p, 484-2 – 484-3.) Further, witness Hunsicker states the Company is in the process of completing the hiring of the aforementioned internal labor to support execution of the work under the contracts. (*Id.*) Witness Hunsicker explained the Company used a disciplined process to forecast the expenses using the fixed fee contracts for software, system integrator professional services, and change management and training professional services as the foundation. (*Id.*) According to witness Hunsicker, these executed contracts account for a significant portion of the overall cost of the program and the contracts specify the amount of labor the Company must provide to execute the contracts. (*Id.*) Finally, witness Hunsicker explains the Company is fully committed to Customer Connect and that no one in this case criticized the necessity of the system or the benefits it will enable for customers. (*Id.* at 484-7.) In fact, according to her, Customer Connect is already providing benefits to customers. (*Id.*) For example, in June 2018, Customer Connect deployed its first release, which is foundational to building a holistic customer profile – gathering all relevant touchpoints customers are having with Duke Energy in real-time, such as web visits, phone calls, power outages, outbound communications and product and service participation. (*Id.* at 484-7 – 484-8.) Also, in February 2019, leveraging insights from the holistic customer profile, the Company began using the new platform to predict the intent of customers when they call. (*Id.*) This and other information has been made more readily available to customer care specialists, who are leveraging it for context into why a customer may be calling, which will allow the specialist to have more informed and productive conversations with customers. (*Id.*)

In surrebuttal testimony, ORS witness Major stated that upon review of Company witnesses Hunsicker and Bateman's rebuttal testimony, the ORS proposes an additional adjustment to O&M expenses for the Customer Connect project to reflect the actual incurred level of expenses in 2018 of $763,000. (Tr. Vol. 6, p. 1238-9.) According to ORS witness Major, this results in an adjustment to O&M expense of $923,000 (as $160,000 of costs associated with Customer Connect were included in the test year expenses). (*Id.*) ORS witness Major recommends the Commission still reject the remaining approximately $550,000 of the Company's proposed adjustment, which still represents forecasted O&M expense. According to ORS witness Major, this amount includes forecasted costs for inflation and contingency, which are not known and measurable. (*Id.*)

At the hearing, Company witness Hunsicker responded by stating the forecasted costs for inflation and contingency was based on a Class Four estimate originally completed in 2016 before the Company completed the design phase of Customer Connect. (Tr. Vol. 4, p, 499.) According to her, the Company is now beyond the Design phase of Customer Connect and, as a result, now considers approximately $370,000 of the original $550,000 forecast as costs correlated with the fixed fee contracts. (*Id.*) Additionally, she identified approximately $20,000 of the remaining

$139,000 as costs associated with inflation. (*Id.*) Finally, according to witness Hunsicker, the remaining approximately $119,000 of the original estimate for contingency was reviewed by the Company's project management center of excellence, who commissioned an independent estimate review committee to review and approve these costs. (*Id.*) If there were to be any amount disallowed from rate recovery in this case related to Customer Connect, it would be the inflation costs of $20,000 and remaining contingency amount of $119,000, not the $550,000 that ORS recommends.

However, upon consideration of all of the evidence in this proceeding, including the improvements to customer service that Customer Connect is delivering and will continue to deliver, the Commission finds and concludes that the Company's requested recovery of its deferred costs[56] and request to include approximately $1.4 million annually for ongoing O&M expenses associated with Customer Connect are approved. The Commission is persuaded that the Customer Connect project will provide value to DE Progress' customers and is necessary for the Company to continue to provide quality service to its customers, which no party contests. Regarding the proposed adjustment for O&M expense, the Commission recognizes these O&M costs are not being capitalized to the program, and in order to be captured, they either need to be included in rates as the Company has requested, or set aside and capitalized to a regulatory asset to be recovered when the project is complete. Further, the Commission agrees with the Company that the forecasted O&M expenses are known and measurable. The known and measurable standard is a standard for recognizing out of period adjustments to historical test-period data. (*See e.g. S.*

[56] The Commission's decision to approve recovery of the Company's deferred Customer Connect costs correlates with the Commission's conclusions regarding whether the Company is entitled to earn a return on deferred capital and operating expenses as addressed in Section C.

Bell Tel. & Tel. Co. v. Pub. Serv. Comm'n, 270 S.C. 590, 602–03 ("Indeed, the Commission must make adjustments for known and measurable changes in expenses, revenues, and investments so that the resulting rates will accurately and truly reflect the actual rate base, net operating income, and cost of capital.") In such cases, changes occurring after the close of the test period may be recognized if they are known (there is a high degree of certainty that change will in fact occur) and measurable (the effect of the change can be accurately quantified in advance). Given the close nexus between the Company's forecasted expenses and the underlying fixed fee contracts, the Commission concludes that the Company's calculation of incremental O&M expenses associated with Customer Connect satisfies this standard. For these reasons, the Commission concludes the Company's adjustment for O&M expense is just and reasonable, and is approved.

Adjustment #32 – Synchronize interest expense with end of period rate base

This adjustment adjusts income taxes for the tax effect of the annualization of interest expense reflected in the pro forma cost of service. (Tr. Vol. 3, p. 320-27.) In her supplemental testimony and exhibits, Company witness Bateman updated this adjustment to reflect additional changes to interest costs. (*Id.* at 322-5.) In contrast to the Company's ($169,000)[57] adjustment to synchronize interest expense for the adjustments to rate base (*see* Hearing Ex. 17 (Bateman Rebuttal Ex. 1, p. 3)), the ORS proposes an adjustment of ($14,000) which reflects ORS' adjustments to income taxes ((Hearing Exhibit No. 44 (Surrebuttal Audit Exhibit KLM-2, p. 4).) In her rebuttal testimony, Company witness Bateman explained that while the amounts calculated by DE Progress and the ORS for this adjustment are different based on other areas of disagreement, the Company and the ORS agree on the concept of and the method used to calculate this

[57] As adjusted subject to the terms of the DE Progress 2018 Rate Case Stipulations.

adjustment. (Tr. Vol. 3, p. 326-20.) In surrebuttal, the ORS updated this adjustment due to an increase in the weighted average cost of debt rate to 4.16% from 4.06% as accepted by ORS witness Parcell in his surrebuttal testimony. (Tr. Vol. 6, p. 1238-14.) Because the Commission has found in favor of DE Progress on the underlying adjustments and ROE, the Commissions finds and concludes that the Company's income tax adjustment is just and reasonable in light of the evidence presented in this proceeding.

Adjustment #33 – Adjust 1/8 O&M for accounting and pro forma adjustments

This adjustment adjusts the DE Progress' rate base to include the additional working capital required as a result of the additional O&M expenses the Company is proposing in this proceeding. In her supplemental testimony and exhibits, Company witness Bateman updated this adjustment to reflect additional changes to cash working capital. In contrast to the Company's ($1,779,000)[58] adjustment to reflect 1/8 of O&M expenses after accounting and pro forma adjustments (*see* Hearing Ex. 17 (Bateman Rebuttal Ex. 1, p. 4d)), the ORS proposes an adjustment of ($860,000)[59] to working capital which reflects ORS' adjustments to O&M expenses ((Hearing Exhibit No. 65 (Surrebuttal Audit Exhibit KLM-2).) In her rebuttal testimony, Company witness Bateman explained that while the amounts calculated by DE Progress and the ORS for this adjustment are different based on other areas of disagreement, the Company and the ORS agree on the concept of and the method used to calculate this adjustment. (Tr. Vol. 3, p. 326-20.) In his surrebuttal testimony, ORS witness Major agreed with this characterization, stating that the ORS and Company amounts differ only due to the underlying adjustments of ORS and the Company and the recommended ROE. (Tr. Vol. 7, p. 1238-14.) Because the Commission has found in favor of

[58] As adjusted subject to the terms of the DE Progress 2018 Rate Case Stipulations.
[59] As adjusted subject to the terms of the DE Progress 2018 Rate Case Stipulations.

DE Progress on the underlying adjustments and ROE, the Commissions finds and concludes that the Company's O&M adjustment is just and reasonable in light of the evidence presented in this proceeding.

Adjustment #36 – Remove certain expenses

ORS proposed to eliminate certain expenses it deemed non-allowable found during ORS' audit of the Company books and records. Specifically, these costs were included in ORS witness Major's proposed Adjustment #36 and include sponsorships, lobbying expenses, service awards, advertising, coal ash litigation expenses, and other miscellaneous expenses such as costs related to the Lineman's Rodeo, employee recognition awards such as service awards, spot awards, and safety awards, as well as 50 percent of dues paid to state and local chambers of commerce, 100% of social and athletic club membership dues, costs that are not 100% related to South Carolina, timing differences due to accrual accounting, and litigation expenses. (Tr. Vol. 6, p. 1236-15.) ORS proposed to adjust O&M expenses by ($875,000) and income taxes by $218,000. (*Id.*) ORS considers these items non-allowable and not necessary to provide electric service to ratepayers. (*Id.*)

ORS performed its non-allowable review of the Company's accounting records over a three-month period, concluded its initial review, and sent its list of non-allowable transactions to the Company on January 28, 2019. (Tr. Vol. 6, p. 1238-10.) ORS requested the Company provide additional supporting documentation and detailed reasoning for why expenses should be allowed and included for recovery from customers. (*Id.*) Subsequently, the Company proposed an adjustment to other O&M expense of ($97,000) and income taxes of $24,000 to remove lobbying costs and image building advertising, and other costs for which the Company is not seeking recovery. (Hearing Ex. 17 (Bateman Rebuttal Ex. 1, p. 3.).) In addition, Company witness

Bateman testified that the Company provided over 64,000 pages of documentation for these transactions in question and the Company's accounting group spent over 1,000 hours pulling the documentation and organizing it in a way to make it easier to follow for the ORS. (Tr. Vol. 3, p. 336.) Witness Bateman explained that this is not a case of lack of documentation, but a case of different perspectives of what should be recoverable. (*Id.* at 337.) The Company believes these costs are just and reasonable in the provision of electric service and should be recoverable, noting that ORS even disallowed items such as sunscreen for distribution field crews. (*Id.*) Witness Bateman quantified the costs at issue as approximately: 1) $117,000 - spot bonuses for exceptional employee contributions; 2) $46,000 - South Carolina chambers of commerce and other South Carolina economic development and community organization; 3) $26,000 – Lineman's Rodeo; 4) $32,000 – service and safety awards; 5) $4,000 – allocations; 6) $12,000 – timing differences, 7) $40,000 – recognition and reward and 8) $390,000 – coal ash litigation expenses. (*Id.* at 337-38.)

On April 15, 2019, Company counsel notified the Commission that the Company and ORS had reached an agreement regarding certain expenses (referred to herein as the Non-allowables Stipulation). (Tr. Vol. 5-1, p. 817.) Specifically, the Company agreed to withdraw its request to recover $39,532 in costs categorized as "Other Employees Recognition & Reward" and $112,736 in costs categorized as "Other Miscellaneous." (*Id.* at 818.) ORS agreed it would no longer contest $26,231 in costs related to the Lineman's Rodeo, $4,066 for costs categorized as "Allocations/Not 100% related to South Carolina," $12,366 for "Accruals/Timing Differences," and half of the $31,655 for costs categorized as "Split Service/Safety Awards." (*Id.* at 818-19.)

In addition, the Company clarified that it does remove expenses it does not believe should be charged to customers such as golf or alcohol and if a mistake is inadvertently made and such an expense is not properly removed, the Company will quickly correct the mistake. (*Id.* at 819.)

The Company continues to believe that meals for traveling employees, modest tools for customer engagement, etc., are important to the Company's operations, but acknowledges that the Company will need to determine ways to provide better context and more detailed explanations to ORS earlier in the audit process. (*Id.* at 821.) In addition, Company counsel explained that some items removed from the non-allowables list originated from the Company's wholesale group. (*Id.*) The Company does not intend for retail customers to pay those types of costs and going forward the Company has put a direct assignment protocol for wholesale costs so this will not be an issue going forward. (*Id.* at 821-22.) However, the Company acknowledged that the Company and ORS may continue to have disputes on principle concerning whether certain costs should be allowed and therefore suggest a separate administrative docket so there is clarity going forward for all parties. (*Id.* at 820.) Counsel for the ORS explained that the ORS audits against a list of "non-allowables" that it has compiled over decades based on prior Commission precedent. (*Id.* at 822.) ORS agreed that an administrative proceeding to take a new look and "refresh the list" is appropriate but cautioned that during the administrative proceeding, ORS is likely to maintain its position that costs related to enhancing employee morale or creating a nice work environment should not be passed on to customers. (*Id.* at 822.)

We find that the Non-Allowables Stipulation is a just and reasonable resolution regarding these costs in this case and is therefore approved. The Company maintains that the remainder of the non-allowable expenses identified by the ORS, not addressed by the Non-allowables Stipulation are properly included in rates as reasonable expenses attributed to prudent utility operations, community engagement, and maintenance of an engaged workforce. (Tr. Vol. 6, p. 1238-11.) We agree and find that these costs are properly included in rates for the reasons discussed further below.

Employee-Related Expenses

Company witness Metzler testified that employee incentives, safety and service awards, and any costs to recognize and reward the Company's employees who serve the Company's customers are reasonable and prudent expenses that seek to enhance employee engagement, and in turn lead to higher levels of customer service, safety and employee recognition. (Tr. Vol. 4, p. 645-13.) Company witness Ghartey-Tagoe also expressed concern with the ORS' recommendation to disallow costs related to employee compensation and employee recognition and engagement. (Tr. Vol. 3, p. 295.) He testified that the Company needs to keep employee engaged and well-trained because businesses with more engaged employees have lower levels of turnover and higher levels of productivity and customer satisfaction. (*Id.*) He explained further that experienced, engaged employees that are incentivized to remain with the Company, to work in a safe manner, and to provide high service levels benefit customers. (*Id.*)

The ORS also questioned other minor grocery items such as coffee provided for Company employees. (Tr. Vol. 6, p. 1238-11.) As previously determined by this Commission, coffee is "not unusual or extravagant and can be considered a necessary part of a decent working environment."[60] Expenses related to employee recognition such as spot bonuses, lump sum merit payments, service awards and safety awards incent employees to provide exceptional performance to the benefit of customers and grocery items such as coffee are part of a decent working environment and are properly included in allowable expenses. Nevertheless, as part of the Non-allowables Stipulation, the Company has agreed to withdraw its request to recover $39,532 in costs categorized as "Other

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[60] *Order Approving Rates and Charges, In Re: Application of Carolina Water Service, Inc., for Approval of New Schedules of Rates and Charges for Water and Sewer Service Provided to its Customers in its Service Area in South Carolina,* Order No. 90-694, PSCSC Docket No. 89-610-W/S (August 1, 1990) at 27.

Employees Recognition & Reward" and the ORS agreed it would no longer contest half of the $31,655 for costs categorized as "Split Service/Safety Awards." The Commission agrees that the terms of the Non-allowables Stipulation are a just and reasonable resolution of these issue in this case and are therefore approved. Remaining at dispute in this category is $116,530 of exceptional contribution awards, which the Commission finds are properly included in allowable expenses.

Lineman's Rodeo

ORS removed costs associated with the Lineman's Rodeo arguing these costs are competitions between linemen from various utilities and not necessary to provide quality electric utility service to customers. (Tr. Vol. 6, p. 1238-11.) ORS further argued that its treatment of rodeo-related expenses is consistent with ORS' treatment of rodeo-related expenses in other South Carolina gas and electric utility rate cases and Rate Stabilization Act filings. (*Id.* at 1238-12.) Company witness Bateman explained that the Lineman's Rodeo is an industry event where line workers share best practices and compete in events where they have an opportunity to display and hone their skills as lineman to provide reliable service to the benefit of customers. (Tr. Vol. 3, p. 326-21.) Thus, there is direct value to customers in ensuring that the Company's line workers continue to learn and hone their skills. Company witness Metzler further explained that the Lineman's Rodeo is an important tool for recruitment because the Company partners with local colleges and lineman schools, where students attend rodeos and volunteer to gain exposure to the field. (Tr. Vol. 4, p. 645-14 – 645-15.) As part of the Non-allowables Stipulation ORS agreed it would no longer contest the $26,231 in costs related to the Lineman's Rodeo, and we find this term of the Non-allowables Stipulation as a just and reasonable resolution of this issue. The Commission believes that because these costs are directly related to ensuring the Company has highly trained line workers and promotes improving skills necessary to provide reliable electric service and attracting a continued pipeline of skilled labor, that these costs directly benefit customers and are properly included in rates. The Commission is cognizant of the excellent work this group of employees has done in numerous ice storms and hurricanes which have plagued South Carolina. As these workers are scarce, and often in harm's way, the State of South Carolina is better off when novel vehicles such as Lineman's Rodeo are employed as a positive way to hone skills and learn best practices.

Community Organizations

The Company further argued that membership dues for local and state South Carolina Chamber of Commerce and other local South Carolina organizations that promote economic development in South Carolina such as the Historic Marion Revitalization Association and the Darlington Downtown Revitalization Association, should be included in rates because these organizations "promote policies, initiatives and principles that benefit all citizens through economic investments, job creation and retention, strong schools, and attracting and retaining business development." (Tr. Vol. 3, p. 326-21 – 326-22.) The ORS maintained that the Company should be permitted to include 50 percent of the state and local chamber dues in rates consistent with past Commission precedent in Commission Order Nos. 94-1229, 01-887, and 02-285. (Tr. Vol. 6, p. 1238-12.) However, ORS maintained that costs related to what the Company identified as "social or athletic" membership club dues such as membership dues related to the Historic Marion Revitalization Association and the Darlington Downtown Revitalization Association should be disallowed 100% based on prior Commission precedent in Commission Order Nos. 91-595 and 94-1229. (*Id.*) The Commission finds these costs totaling $45,559,000 are generally related to promoting business, economic development and supporting the communities served by the Company and therefore are appropriately included in rates. Without local offices (and their associated expense), the Commission finds it important and necessary to customers in this State for the Company to be actively involved with the communities it serves. It is logical that community engagement can yield higher customer satisfaction and conflict resolution than if the Company did not participate at the local level in the community. The Commission cautions the Company this is not a carte blanche approval of all community activities, and in the future the Company should—and will be expected—to continue to provide information as to how it serves and responds to the needs of customers through such channels.

Allocation of Transmission Vehicle Costs

ORS also proposed disallowing certain costs that it argued are not 100 percent attributable to South Carolina such as North Carolina Department of Motor Vehicle registration fees paid for transmission vehicles which are allocated between North Carolina and South Carolina customers. (Tr. Vol. 6, p. 1238-13.) The Company testified that it is appropriate to allocate both South Carolina and other jurisdictional costs between South and North Carolina customers and noted that ORS did not make an adjustment to accept the full cost of South Carolina-specific costs the Company allocated between North Carolina and South Carolina. (Tr. Vol. 3, p. 326-22 - 326-23.) ORS maintained that the Company had not provided explanations for the transactions ORS proposed to disallow and therefore it was not able to review support provided by the Company necessary for ORS to modify its adjustment and should reject the Company's position. (Tr. Vol. 6, p. 1238-13). As part of the Non-allowables Stipulation, the ORS agreed to no longer contest the $4,066 in this category. The Commission finds that this term of the Non-allowables Stipulation is approved as a just and reasonable resolution of this issue in this case and that it is appropriate to allocate system-wide costs for shared assets, and these expenses are properly included in rates.

Accruals

The ORS also proposed disallowing certain transactions based on timing differences. (Tr. Vol. 6, p. 1238-13.) ORS removed various transactions based on the invoice date and the date the invoice was paid being in different calendar years. (*Id.*) The Company explained that its test year was representative of the Company's expenses in a 12-month period and that it may incur certain costs in one year, but those costs may not be paid until the following year due to accrual accounting. (Tr. Vol. 3, p. 326-23 – 326 -24.) ORS maintained that the Company had not provided explanations for the transactions ORS proposed to disallow and therefore it was not able to review support provided by the Company necessary for ORS to modify its adjustment and should reject the Company's position. (Tr. Vol. 6, p. 1238-13). As part of the Non-allowables Stipulation, the ORS agreed to no longer contest the $12,366 in this category. The Commission finds that this term of the Non-allowables Stipulation is approved as a just and reasonable resolution of this issue in this case and that the test year is representative of the costs the Company incurs in a 12-month period and as a result of accrual accounting, these costs are properly included in rates and are approved.

Coal Ash Legal Costs

In DE Progress' Application, the Company requested recovery of a variety of litigation expenses, including legal fees related to ongoing coal ash litigation, pursuit of the Company's affirmatively filed suit against its insurers to enforce coverage of coal ash-related claims, and defense of state enforcement actions brought by various non-governmental entities.

In direct testimony, ORS witness Willie Morgan recommended that the Commission disallow $875,000 (Hearing Ex. 65 (Surrebuttal Audit Exhibit KLM-2, p. 4)) of the Company's litigation expenses related to coal ash —specifically, (1) the insurance recovery litigation DE

Progress initiated to recuperate costs of coal ash remediation, and (2) the defense of state enforcement actions brought by non-governmental advocacy groups. (Tr. Vol. 5-1, p. 839-26.) Witness Morgan contended that customers should not bear the burden of legal costs related to the Company's failure to operate its coal ash basins in accordance with state and federal rules and regulations. He claimed that inclusion of the legal costs would force ratepayers to pay for DE Progress' failure to comply with the law. He asserted that legal expenses are not related to providing adequate electrical service, and that customers derived no benefit from the expenditures. He reasoned that legal costs should be shareholders' responsibility and claimed that this in turn incentivizes the regulated utilities to operate in compliance with federal, state, and local laws. (Tr. Vol. 7, p. 1321-6.)

Witness Wright rebutted ORS witness Morgan's proposed adjustment to disallow recovery of $875,000 in legal costs related to the Company's ongoing insurance recovery litigation and defense of state enforcement actions. Witness Wright noted that legal fees should be recoverable because they represent a legitimate, reasonable, and prudent business expenditure, and the Company is often considered a "target" for litigation and must be allowed to vigorously defend itself—particularly from lawsuits initiated by non-government related parties, like the ones witness Morgan has placed at issue. (*Id.* at 1321-27—1321-28.) He explained that the legal costs witness Morgan seeks to disallow are not, as he contends, the result of any failure to operate its coal ash basins in accordance with the law, but rather relate to insurance litigation initiated by the Company for the benefit of its customers. If the Company prevails, the costs recovered from insurers will be passed along to customers. With respect to the state enforcement action, witness Wright testified that the Company should defend itself and ratepayers in a legal proceeding when the potential result could require the Company to undertake coal ash remediation procedures that go beyond current regulatory requirements—particularly when these lawsuits are brought by non-government entities. He concluded that because the legal fees incurred in both lawsuits are targeted to an end-goal that would benefit customers, they are legitimate and recoverable. (*Id.* at 1321-29.)

Citing to a decision of this Commission published in January of this year, ORS argued that litigation costs should be disallowed when incurred to unsuccessfully defend against "claims asserting failure of the utility to adhere to state or federal law[.]" *In re: Application of Carolina Water Service, Inc. for Approval of an Increase in Its Rates for Water and Sewer Services*, Docket No. 2017-292-WS, Order No. 2018-802 (Jan. 25, 2019). ORS witness Hamm testified on surrebuttal to his belief that the Commission has adopted a regulatory policy of disallowing legal costs and expenses incurred as a result of legal disputes in which the utility was found at fault and was unable to demonstrate its achievement of an outcome that provided economic benefit to its customers. (Tr. Vol. 7, p. 1323-3—1321-8.) Witness Hamm concluded that because DE Progress has not provided the Commission with "clear and detailed information" supporting its claim for recovery of litigation expenses, those expenses should be borne by stockholders and disallowed in recovery from ratepayers. (*Id.* at 1323-8.)

Although Order No. 2018-802 disallowed recovery of certain litigation expenses, the order did not summarily bar recovery of all litigation expenses incurred by a utility. (*Id.*) Instead, Order No. 2018-802 allowed recovery of litigation expenses where the utility's decision to incur such expenses was based upon "smart strategic effort[s]," even where the utility was ultimately unsuccessful in the litigation at issue. (*Id.*) Similarly, in the Commission's *Order on Remand* issued in Docket No. 88-11-E on July 9, 1990, the Commission found "that the [the utility] [has] an obligation to the ratepayers as well as the shareholders to defend itself against [] lawsuits and that ratepayers benefit from the [utility's] defense of such." *In re: Application of Carolina Power & Light Company for General Increase in Rates and Charges* Order No. 88-864, at 60, Docket No. 88-11-E (July 9, 1990) ("1990 CP&L Rate Case"); *see also In re: Application of South Carolina Electric and Gas Company for adjustments in electric rate schedules, tariffs, and contracts,* Order No. 80-375, Docket No. 79-196-E (June 30, 1980) (approving recovery of SCE&G's litigation expenses, including legal fees incurred for a dispute involving performance of SCE&G's nuclear fuel supply contract, which expenses the Commission stated "legitimately operate[] to protect the interests of the company and its ratepayers").

At issue in the 1990 CP&L Rate Case were legal expenses incurred by CP&L to defend the company against a lawsuit filed by the United Mine Worker's Association ("UMWA"). *Id.* at 59-60. Although the consumer advocate argued that legal fees associated with the UMWA lawsuit were not "directly related to the provision of electric service," the Commission disagreed, finding that "[w]ith respect to the UMWA lawsuit…the coal mines in question were purchased by the Company to provide low-sulfur coal and CP&L's ratepayers did in fact receive a benefit from the low-sulfur coal supplied from these mines." (*Id.* at 60.) The Supreme Court of South Carolina later confirmed the Commission's decision as it related to CP&L's recovery of litigation expenses. *See Hamm v. S.C. Pub. Serv. Comm'n,* 307 S.C. 188, 198, 414 S.E.2d 149, 154-55 (1992) (stating that the "PSC found ratepayers benefitted from CP[&]L's defense of these lawsuits which could have result in greater costs to the company").

Taking into consideration that recent guidance, the Commission finds that DE Progress' coal ash insurance litigation expenses at issue here are distinguishable from those expended and disallowed by Carolina Water Service, Inc. As witness Wright noted, the legal costs ORS seeks to disallow are not, as witnesses Major and Hamm contend, the result of any failure to operate the

Company's coal ash basins in accordance with the law. To the contrary, witness Wright explained that the insurance litigation in question was initiated by the Company for the benefit of its customers to enforce insurance policies and obtain indemnity from insurers for costs incurred associated with coal ash remediation and is unrelated to any environmental violations. (Tr. Vol. 5, p. 839-29.) While the value and recoverability of the insurance coverage is heavily disputed, the total insurance available from all of the policies sued upon by DE Progress may total anywhere between $172 million to $200 million per occurrence, depending on the policy pay limit. (Hearing Exhibit 71.) If the Company prevails in this insurance litigation, witness Wright noted that the costs it recovers from insurers will be credited to customers. (Tr. Vol. 5, p. 839-29.) The Commission thus finds that DE Progress has reasonably pursued this type of recovery, which could pass along a substantial benefit to its customers.

As to the other legal fees with which ORS takes issue, DE Progress incurred those fees to defend claims that were filed against the Company in 2013, well before the passage of either CAMA or the CCR Rule, by non-governmental entities after North Carolina regulators declined to pursue the underlying claims. To date, there has been no court finding in these actions that the Company violated any environmental statute or rule, nor has the Company admitted any fault or violation. In rebuttal testimony, witness Wright argued, and the Commission agrees, that the Company has a duty to customers to defend itself in litigation of this sort. We also agree that the fact that allegations of violations have been made against the Company does not mean that those allegations are true, (*Id.* at 839-27.), and conclude therefore that such allegations should not be relied upon to disallow recovery of legal expenses.

Finally, as witness Wright noted, legal fees should be recoverable because they represent a legitimate, reasonable, and prudent business expenditure, and ORS has presented no argument under the applicable regulatory standard to suggest otherwise. Accordingly, because the legal fees incurred in both lawsuits are targeted to an end-goal that would benefit customers, the Commission finds that such legal fees are legitimate and recoverable. (*Id.* at 839-25.)

Taking into consideration that recent guidance, the Commission finds that DE Progress' coal ash litigation expenses at issue here are distinguishable from those expended and disallowed by Carolina Water Service, Inc. As witness Wright noted, the legal costs ORS seeks to disallow are not, as witnesses Morgan and Hamm contend, the result of any failure to operate the Company's coal ash basins in accordance with the law. To the contrary, witness Wright explained that the insurance litigation in question was initiated by the Company for the benefit of its customers to enforce insurance policies and obtain indemnity from insurers for costs incurred associated with coal ash remediation and is unrelated to any environmental violations. (*Id.* at 839-26.) If the Company prevails in this insurance litigation, witness Wright noted that the costs it recovers from insurers will be credited to customers. (*Id.* at 839-29.) The Commission thus finds that DE Progress has reasonably pursued this type of recovery, which could pass along a substantial benefit to its customers.

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Finally, as witness Wright noted, legal fees should be recoverable because they represent a legitimate, reasonable, and prudent business expenditure, and ORS has presented no argument under the applicable regulatory standard to suggest otherwise. Accordingly, because the legal fees incurred in both lawsuits are targeted to an end-goal that would benefit customers, the Commission finds that such legal fees are legitimate and recoverable. (*Id.* at 839-25.)

Adjustment #38 – Adjust for Ongoing Payment Obligation

In DE Progress' Application, the Company also requested recovery of legal fees and ongoing settlement payment obligations related to a contract dispute DE Progress settled over an amended and restated Agreement entered into with CertainTEED for the sale and delivery of Gypsum Filter Cake ("CertainTeed Agreement"). For both categories, the Company argued that its litigation costs were legitimate, reasonable, and prudently incurred and, therefore, recovery should be allowed.

Witness Morgan argued that the Company's litigation expenses associated with the CertainTEED Agreement should be disallowed, based upon the finding of the appealed, North Carolina Superior Court Order related to the contract dispute concerning the CertainTEED Agreement. Citing to the North Carolina Superior Court's Order included as an exhibit to his testimony, witness Morgan summarily argued that the Company had "fail[ed] to meet its [CertainTEED Agreement] obligations," despite also testifying that DE Progress, as well as CertainTEED, had appealed the North Carolina Superior Court Order and ultimately settled the dispute on their own. (Tr. Vol. 7, p. 1321-6; *see also* Hearing Ex. 68 (Morgan Direct Exhibit 2).) Based upon this conclusion and reliance on the North Carolina Superior Court Order, he argued that DE Progress' legal fees incurred to defend the Company "provided no benefit to ratepayers," and, additionally, did "not relate[] to providing adequate electrical service to customers," and recommended a disallowance of the Company's related legal fees as identified in ORS witness Major's Adjustment #36. (*Id.*) He similarly argued that DE Progress' payments to CertainTEED resulting from the settlement agreement did not benefit ratepayers or relate to providing adequate electrical service to customers, and recommended that the Company's litigation expenses resulting from the CertainTEED Agreement be disallowed. (*Id.* at1321-7.)

During the hearing, Company witness Coppola provided background on the Company's CertainTEED Agreement and explained that but for the CertainTEED Agreement, the Company would otherwise have to pay for, and pass on to customers, disposal costs for gypsum generated by the Company's coal-fired generators. She explained that the CertainTEED Agreement litigation arose over whether DE Progress had an obligation to provide gypsum on an "as available" basis—which "as available" basis CertainTEED had consistently sought in the past—or a on contractually-fixed, monthly basis, pursuant to the terms of the CertainTEED Agreement. She reiterated that although the North Carolina Superior Court found DE Progress in breach of the CertainTEED Agreement, both CertainTEED and DE Progress filed appeals to the order. She also elaborated on the benefits of DE Progress' settlement with CertainTEED, testifying that the settlement resulted in the Company paying CertainTEED lower liquidated damages than what the Company would have otherwise payed pursuant to the North Carolina Superior Court Order. She concluded by noting that the subject of the CertainTEED Agreement, the sale of gypsum, was directly the result of the Company operating its coal-fired generating units for the generation of electricity, and thus the result of providing electric service to ratepayers. (Tr. Vol. 5-2, p. 914-917.)

When questioned by Commission Hamilton, witness Coppola testified that ratepayers receive a $50 million savings benefit as a result of the Company's management decisions to enter into, litigate, and settle upon the CertainTEED Agreement, net of DE Progress' litigation expenses. (*Id.* at 921-922.)

On re-direct, witness Coppola provided a detailed breakdown of the ratepayer savings benefits resulting from the CertainTEED Agreement, testifying that ratepayers saved approximately $12 million in avoided stockpile management costs, $116 million in avoided landfill disposal costs, and received $17 million in revenues from the sale of gypsum, net of the Company's total litigation expenses. (*Id.* at 923-925.)

Company witness Coppola also rebutted ORS witness Morgan's assertion that the CertainTEED Agreement was unrelated to DE Progress' provision of adequate electrical service. She explained that it is undisputed that environmental control equipment installed on coal-fired generation plants known as "scrubbers" produces gypsum as a by-product of operation, and that coal-fired generation plants solely operate to provide adequate, electrical service to customers. Therefore, witness Coppola testified that it was unreasonable to contend that the CertainTEED Agreement was unrelated to the Company's provision of adequate electrical service. (*Id.* at 918-3 – 918-4.)

Witness Coppola next disagreed with witness Morgan's assertion that the CertainTEED Agreement, and the Company's defense of it, did not benefit ratepayers. She explained that DE Progress had two choices regarding how to handle the gypsum by-product subject to the CertainTEED Agreement: either (1) dispose of the gypsum at a cost to customers; or (2) sell the gypsum to beneficial reuse companies for proceeds to be passed on to customers. Witness Coppola testified that it logically follows that customers would prefer receiving a financial benefit from selling the gypsum as a beneficial refuse product. (*Id.* at 918-4–918-5.)

Finally, witness Coppola disagreed with ORS witness Morgan's legal conclusion that DE Progress has in fact breached the CertainTEED Agreement, and that litigation expenses resulting from the CertainTEED Agreement are not recoverable. In addition to citing Company witness Wright's testimony addressing this topic, witness Coppola testified that the fact of a contractual counter party's allegation of breach of contract does not mean the allegation is actually true. For this reason, witness Coppola testified that the Company reasonably incurs legal costs for the benefit of customers to defend itself in lawsuits where such allegations are made. She pointed out that neither witness Morgan, nor any other party, contend that the Company was imprudent in entering into, executing, or defending the CertainTEED Agreement. (*Id.* at 918-5—918-6.)

ORS witness Morgan addressed Company witness Coppola's rebuttal testimony regarding the Company's request to recover litigation expenses related to the CertainTEED Agreement. He stated that Company witness Coppola had mischaracterized ORS' position regarding the Company's ongoing settlement payment obligation, stating that the ORS agrees that the sale of a coal-ash byproduct to companies like CertainTEED may benefit customers. (Tr. Vol. 7, p. 1323-4.) He also testified that witness Coppola did not provide an explanation of the services or benefits DE Progress customers receive in exchange for the payment obligations to CertainTEED as a result of the settlement, and recommended that DE Progress be disallowed from recovering the ongoing payment obligation to CertainTEED. (*Id.* at 1323-5.) Citing again to the North Carolina Superior Court Order, witness Morgan additionally argued that the Company was "not successful" in its defense of the CertainTEED litigation, and that DE Progress should therefore also be disallowed recovery of litigation fees related to the CertainTEED Agreement. (*Id.*; *see also* Hearing Ex. 68 (Morgan Direct Exhibit 2.).)

Witness Hamm also addressed the Company's request to recover litigation costs and expenses related to the CertainTEED Agreement and Company witness Coppola's corresponding rebuttal testimony. He explained that DE Progress paid approximately $1,084,000 for the Company's alleged breach, and $88 million in liquidated damages to CertainTEED as part of the CertainTEED Agreement settlement, but indicated it was impossible to know, based on information supplied by the Company, if any of those legal expenses are included in this rate proceeding. (Tr. Vol. 7, p. 1310-9 – 1310 -10). He stated that DE Progress provided no evidential basis for recovery of the CertainTEED Agreement litigation expenses, and cited to the appealed North Carolina Superior Court ruling in favor of CertainTEED to argue that customers "should not be held responsible for the Company's decision to pursue intensive litigation" that ends in settlement. (*Id.* at 1310-11—1310-12). He further testified that ORS' position helps to ensure that the Company carefully manage its operation and consider the costs that pursuing litigation could potentially have for its customers. (*Id.* at 1310-10—1310-11.)

In sum, ORS argued that the Company's legal fees incurred to defend the CertainTEED Agreement should be disallowed per ORS Adjustment #36, and that the Company's ongoing payment obligation resulting from the CertainTEED Settlement should similarly be disallowed per ORS Adjustment #38. Based on the same argument explained above regarding disallowance of DE Progress' coal ash litigation expenses, ORS again cited to Commission Order No. 2018-802, holding that South Carolina public utilities are "required to operate [their] facilities in compliance with federal and state law" and correspondingly, that recovery of litigation expenses is improper where "the ratepayers [are] already paying for the [utility] to provide its services in compliance with its permits and with applicable federal and state laws, and, accordingly, are not deriving any benefit from the [litigation] expenditure," in support of ORS proposed Adjustments #36 and #38 relating to the CertainTEED Agreement. (*Id.*) Finally, ORS argued that, as a policy matter, "Company management [should] not be rewarded for failure to comply with federal and state laws." (*Id.* at 1310-11.)

Again, in reliance upon the above precedent discussed in the Coal Ash Legal Costs section for Adjustment #36, the Commission finds DE Progress' litigation expenses, including legal fees to defend the CertainTEED Agreement and ongoing settlement payments resulting from the same, to be distinguishable from the litigation expenses disallowed in Commission Order No. 2018-802. As an initial matter, the North Carolina Superior Court's finding that DE Progress was in breach of the CertainTEED Agreement does not equate to a "violation of state or federal law." By its very name, a breach of contract is simply that—a break with the terms of an agreement between two or more independent parties—*not* a violation of federal or state law.[61] Moreover, there are any number of reasons why a decision to break with the terms of an agreement might be more beneficial to a contracting party—and, in the case of DE Progress, more beneficial to its customers—than continuing to honor its terms. Here, neither ORS nor the North Carolina Superior Court Order relied upon by ORS cite to any federal or state law that DE Progress has "violated," even assuming that DE Progress was in fact in breach of the CertainTEED Agreement. In addition, we note that disputed matters are settled frequently, for many reasons other than settling parties' underlying view of the merits of the case. Therefore, the Commission does not find DE Progress'

[61] *See* Black's Law Dictionary (10th ed. 2014) defining "breach of contract" as "violation of a contractual obligation by failing to perform one's own promise, by repudiating it, or by interfering with another party's performance."

decision to settle the matter evidence that DE Progress was, in fact, in breach of the CertainTEED Agreement.

Even casting aside ORS' misinterpretation of the North Carolina Superior Court Order and in further contrast to the ratepayers concerned in Order No. 2018-802, DE Progress' ratepayers were not, as ORS contends, "already paying for the Company to provide its services in compliance with" the CertainTEED Agreement. To the contrary, DE Progress' ratepayers were, instead, receiving a direct financial benefit as a result of the Company's management decisions to enter into, litigate, and settle the CertainTeed Agreement. Had the Company not made these managerial decisions with relation to the CertainTEED Agreement, customers would be paying an additional $50 million in gypsum-related disposal costs. (Tr. Vol. 5-2, p. 920-925.) ORS witness Morgan contends as much in his surrebuttal testimony, stating that agreements such as the CertainTEED Agreement "may" benefit ratepayers. (Tr. Vol. 7, p. 1323-4.) Concerning the Company's specific decision to appeal the North Carolina Superior Court Order and enter settlement, the Commission finds persuasive the fact that the Company's settlement agreement resulted in lower ongoing payment obligations than initially ordered by the North Carolina Superior Court Order (Tr. Vol. 5-2, p. 922-923.), evidencing that the Company's litigation strategy to appeal the North Carolina Superior Court Order and enter into settlement was to the benefit of ratepayers. Therefore, the Commission finds that the Company's decision to incur the CertainTEED litigation expenses was strategic, reasonable, and prudent, and that the Company's litigation expenses directly benefitted ratepayers.

The Commission additionally finds, and agrees with Company witness Coppola, that the CertainTEED Agreement, and litigation and settlement arising out of the same, directly related to the Company's provision of reliable, electric service. (*Id.* at 918-3—918-4.) Similar to the allowed UMWA lawsuit expenses at issue in the 1980 CP&L Case, the litigation expenses at issue here also concern the underlying utility activity of supplying economically dispatched, coal-fired generation, which generation directly relates to DE Progress' provision of reliable, electric service. In fact, the North Carolina Superior Court affirmatively found that DE Progress' general undertaking of the CertainTEED Agreement was "consistent with[] [DE Progress'] Primary Purpose of producing reliable and economical electricity." (Hearing Ex. 68 (Morgan Direct Exhibit 2 at p. 2.)). Accordingly, the Commission rejects ORS' arguments and the corresponding disallowances recommended by ORS witnesses Morgan, Major, and Hamm relating to the Company's CertainTEED Agreement.

<u>Adjustment #40 – Customer Growth</u>

The Company proposes an adjustment of $17,000 to reflect customer growth after accounting and pro forma adjustments by using net income for return and a customer growth factor of 0.027%. (*See* Hearing Ex. 17 (Bateman Rebuttal Exhibit 1 at p. 1; Tr. Vol. 6, p. 1236-16.) ORS witness Seaman-Huynh testified that ORS found an increase in the number of DE Progress customers in South Carolina when comparing the end of the test year and the average number of customers during the test year. (Tr. Vol. 6, p. 1099-17.) To capture the additional revenues and expenses generated by customers added to the Company's system, ORS included an adjustment for customer growth. (*Id.*) Witness Seaman-Huynh explained that the customer growth factor is calculated by taking the difference between the total number of customers at the end of the test year and the average number of customers during the year and dividing the result by the average number of customers during the test year. (*Id.*) This methodology yields a retail customer growth factor of 0.0267% for the Company. (*Id.*) In her rebuttal testimony, Company witness Bateman explained that while the amounts calculated by DE Progress and the ORS for this adjustment are different based on other areas of disagreement, the Company and the ORS agree on the concept of and the method used to calculate this adjustment. (Tr. Vol. 3, p. 326-24.) In his surrebuttal testimony, ORS witness Major agreed with this characterization, stating that the ORS and Company amounts differ only due to the underlying adjustments of ORS and the Company and the recommended ROE. (Tr. Vol. 7, p. 1319-14.) Because the Commission has found in favor of DE Progress on the underlying adjustments and ROE, the Commissions finds and concludes that the Company's customer growth adjustment is just and reasonable in light of the evidence presented in this proceeding.

Adjustment #41 – Adjust Revenue, Taxes, and Customer Growth for the Proposed Increase

The Company proposes to adjust electric operating revenue by $68,501,000, general taxes by $303,000, income taxes by $17,016,000, and customer growth by $14,000 for the proposed revenue increase. (Hearing Ex. 17 (Bateman Rebuttal Ex. 1, p. 1).) ORS proposes to adjust electric operating revenue by $32,130,000, general taxes by $142,000, income taxes by $7,981,000, and customer growth by $6,000 for the ORS proposed revenue increase and to achieve an ROE of 9.3% as recommended by ORS witness Parcell. (Hearing Exhibit No. 65 (Surrebuttal Audit Exhibit KLM-1).) In his surrebuttal testimony, ORS witness Major testified that while the amounts calculated by DE Progress and the ORS for this adjustment differ due to the underlying adjustments of ORS and the Company and the recommended ROE, the Company and the ORS agree on the concept of and the method used to calculate this adjustment. (Tr. Vol. 6, p. 1238-14.) Because the Commission has found in favor of DE Progress on the underlying adjustments and ROE, the Commissions finds and concludes that the Company's adjustments outlined herein are just and reasonable in light of the evidence presented in this proceeding.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NO. 40

The evidence in support of the findings of fact are found in the verified Application, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

In her direct testimony, Company witness Ward supports the fuel component of proposed base rates for all customer classes and the fuel pro forma adjustments to the test year operating expenses contained in Hearing Ex. 14 (Bateman Exhibit 1.) (Tr. Vol. 4, p. 636-3.) Specifically, as shown on Ward Revised Exhibit 1, the Company's South Carolina retail adjusted fuel costs expenses for the test year was $170,748,754. (*Id.* at 636-4.) This amount was provided to witness Bateman and is reflected in the operating expenses shown on Hearing Ex. 14 (Bateman Exhibit 1). The proposed base fuel factors are comprised of the total of fuel, environmental, DERP avoided costs, and the capacity related costs, including the Public Utility Regulatory Policies Act ("PURPA") purchased power capacity cost factors, by customer class, most recently approved in Docket No. 2018-1-E for effect July 1, 2018. (*Id.*) Accordingly, the Company proposes to use the following base fuel factors by customer class (excluding gross receipts tax and regulatory fees):

- Residential 3.087 cents per kWh
- General Service-Non Demand 2.801 cents per kWh
- General Service-Demand 2.366 cents per kWh, 89 cents per KW
- Lighting 2.366 cents per kWh

Witness Ward stated the Company will continue to bill customers the fuel rates authorized by the Commission in its annual fuel proceedings. (*Id.* at 636-5 – 636-6.) As such, since the Company's requested increase in revenues in this case is related to non-fuel revenues, there will be no change in customers' bills as a result of including these fuel cost factors in the proposed base rates. (*Id.* at 636-6.)

No intervenor contested the testimony of Company witnesses Ward and Bateman that support the base fuel and fuel-related cost factors therein. Accordingly, the Commission finds and concludes that the base fuel and fuel-related cost factors are just and reasonable to all Parties in light of all the evidence presented, and are approved

EVIDENCE FOR FINDINGS AND CONCLUSIONS NO. 41

The evidence in support of the findings of fact are found in the verified Application, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

Company witness Hager explained in her testimony that the purpose of the Company's Cost of Service Study ("COSS") is to align the total costs incurred by DE Progress in the Test Period with the jurisdictions and customer classes responsible for the costs. (Tr. Vol 4, p. 701-3.) The COSS is based on the official accounting books and records of DE Progress, supported in this proceeding by Company witness Doss. The cost components are comprised of the Company's electric operating expenses and original cost rate base and are based on the historic 12-month Test Period covering January 1, 2017 through December 31, 2017.

The COSS directly assigns or allocates the Company's revenues, expenses, and rate base among the regulatory jurisdictions and customer classes served by the Company based upon the service requirements of those respective jurisdictions and customer classes. These service requirements are based on a number of factors, including differences in usage patterns and size.

Witness Hager said that cost causation is a key component in determining the appropriate assignment of revenues, expenses, and rate base among jurisdictions and customer classes. (*Id.* at 701-4.) Under the principle of cost causation, costs are assigned to the specific jurisdictions and customer classes that "caused" such costs to be incurred.

After all costs and revenues are assigned, the COSS identified the return on investment the Company has earned for each customer class during the test period. These returns can then be used as a guide in designing rates to provide the Company an opportunity to recover its costs and earn its allowed rate of return.

Once the costs of service are identified, witness Hager explained that they are grouped according to their "function." Functions include production (generation), transmission, distribution, and customer service, billing and sales. The functionalized costs are then grouped or classified based on the utility "operation" or service being provided and the related causation of the costs. Typical classifications include demand, energy, and customer-related costs. Finally, the costs, which have been functionalized and classified, are allocated or directly assigned to the proper jurisdiction and customer class based on the manner in which the costs are incurred (*i.e.,* based on cost causation principles).

Witness Hager testified that demand-related costs are costs incurred that vary in direct relationship to the kW of demand that customers place on the various segments of the system. (*Id.* at 701-7.) Costs that are classified as demand-related include major portions of the Company's investment and related expenses in its production and transmission facilities and a significant portion of the investment and related expenses of its distribution system. These costs tend to remain constant over the short run and do not change based on the amount of energy consumed. These costs are often referred to as fixed costs. Energy-related costs are costs incurred that vary in direct relationship to the amount of energy or kWh generated and delivered. These costs are often referred to as variable costs. Finally, customer-related costs are costs incurred as a result of the number of customers being served. Customer costs do not vary with the customers' volume of usage but are related to the number of customers.

Witness Hager explained that cost components identified as having a direct relationship to a jurisdiction or customer class are directly assigned to that jurisdiction or class before any allocations occur. (*Id.* at 701-7.) The remaining costs are allocated based on specific allocation factors related to (1) demand, (2) energy, and (3) customer-related classifications.

According to witness Hager there are two categories of demand-related costs used in the COSS: 1) production and transmission demand related costs; and 2) distribution plant investments. Production and transmission demand costs are allocated using the SCP method. (*Id.* at 701-8.) Distribution plant investments are directly assigned to the jurisdictions. At the customer class level, substations, and a part of poles, lines and transformers that have been designated as demand-related are allocated based on Non-Coincident Peak Demand ("NCP").

Witness Hager explained that a coincident peak ("CP") allocator assigns the fixed demand-related costs (for example, a portion of production and all transmission-related costs) to the jurisdictions and customer classes in proportion to their respective contribution to the system's peak hourly demand during the test period. (*Id.* at 701-8 – 701-9.) Each jurisdiction and customer class' cost responsibility (*i.e.*, the percentage of the fixed portion of production and transmission demand costs assigned to each jurisdiction and customer class) is equal to the ratio of their respective demand in relation to the total demand placed on the system. The Company's COSS proposed rate design in this proceeding allocates the fixed portion of production and transmission demand-related costs based upon a jurisdiction's and customer class' coincident peak responsibility occurring during the summer of the test year which occurred on July 13, 2017, at the hour ending 5:00 PM and was 12,590 MWs. (*Id.* at 701-9.)

Witness Hager explained that its SCP was not the system peak for the test year. (*Id.*) The DE Progress system peak occurred on January 9th in the hour ending 8:00 AM and was 14,407

MWs. (*Id.*) Because the Company's generation and transmission investments being considered for cost recovery in this case were made based on summer peak planning, for consistency, the Company continued to use the summer peak for cost allocation. (*Id.* at 701-9 – 701-10.) Witness Hager testified that witness Wheeler considered the winter peak in rate design. (*Id.* at 701-10.) No party to the proceeding challenged the Company's use of the SCP.

Regarding the allocation of distribution investments, witness Hager testified that they are first identified and directly assigned to the state in which they are located. (*Id.*) Then those distribution costs that are identified as customer-related are allocated based on customer allocation factors. The remainder of the distribution costs are designated as demand-related and allocated to the customer classes based on NCP demand allocators.

Witness Hager explained that DE Progress allocated the operating expenses of the service drop and meter, meter reading, billing and collection, and customer information and services, which are included in FERC accounts 901-917 in the customer class category of costs. (*Id.* at 701-12.) In addition, DE Progress included in this category a portion of distribution costs that the Company identified as customer-related.

In DE Progress' last rate case, the Company allocated meters and service drops (FERC Accounts 369 and 370) and a portion of transformers (FERC Account 368) as customer related and allocated the remaining distribution plant and associated costs as demand related. In this case, witness Hager testified that the Company identified a portion of the costs of that remaining distribution plant - lines, poles, and transformers (FERC Accounts 364-368) to be allocated as customer-related. (*Id.*)

The Company relied upon The National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual ("CAM") to support its change in the allocation of its distribution costs. Witness Hager testified that the CAM states that a portion of distribution costs related to FERC Accounts 364-368 are customer-related. (*Id.* at 701-13.) These FERC accounts include the costs of poles, towers, fixtures, overhead and underground conductors, and transformers. The two-methods the CAM discusses for allocating these customer-related distribution costs are:

1) Minimum System Method (called Minimum-Size Method in the NARUC Manual); and
2) Zero-Intercept Method (called Minimum-Intercept Method in the NARUC Manual).

Both methods recognize that some portion of the distribution system is necessary to serve customers, regardless of whether the customers take any energy from the system. The Minimum System Method seeks to determine the minimum size distribution system that can be built to serve the minimum loading requirements of customers. The Minimum System Method develops the cost of the minimum set of distribution assets that would be needed to serve customers and allocates those costs based on the number of customers.

Similar to the Minimum System Method, the Zero-Intercept Method allocates a portion of the same distribution accounts on the basis of the number of customers. The Zero-Intercept Method seeks to identify the portion of distribution plant that is associated with no load using regression techniques.

DE Progress chose to use the Minimum System Method approach in its COSS Study for allocating costs to its customers, which the Company asserts is appropriate for allocation of customer-related distribution costs. Witness Hager explained that the Zero-Intercept Method is generally considered to be a more complex and time-consuming methodology that often can produce results that are not materially different from the Minimum System Method. (*Id.* at 701-14.) She opined that theory behind use of a minimum system study is sound and consistent with cost causation which is the foundation of the COSS. (*Id.*) DE Progress' Minimum System Study allowed DE Progress to classify the distribution system into the portion that is customer-related (driven by number of customers) and the portion that is demand-related (driven by customer peak demand levels).

Witness Hager testified that every customer requires some minimum amount of wires, poles, transformers, etc. to receive service; therefore, every customer "caused" DE Progress to install some amount of such distribution assets. (*Id.*) The concept DE Progress used to develop its Minimum System Study was to consider what distribution assets would be required if every customer had only some minimum level of usage (e.g., one light bulb). This methodology allowed the Company to assess how much of its distribution system is installed simply to ensure that electricity can be delivered to each customer, if and when the customer chooses to use electricity. Once minimum system costs were identified, all distribution costs over the minimum system costs and direct assignments were determined to be demand-related.

The use of the minimum system approach resulted in the Company allocating additional costs to the customer class cost category and a corresponding reduction in the costs allocated to the energy and demand related cost categories. All costs are allocated. The issue is which are designated demand-related, energy-related, or customer-related. By re-assigning certain distribution costs from the demand-related cost category to the customer class cost category, the minimum system methodology results in a higher fixed BFC and a lower demand charge for customers whose electric rate includes demand charges and lower energy charges for those without demand charges than would otherwise be the case. According to the Company, without the use of the minimum system allocation methodology, low-use customers on rate schedules without demand charges avoid paying for the infrastructure necessary to provide service to them which is counter to cost causation principles. (*Id.* at 701-15.) Witness Hager stated that witness Wheeler relied upon costs allocated as being customer-related in the COSS in developing his recommendation regarding the BFCs. (*Id.* at 701-16.) Witness Hager concluded that the Minimum System methodology is consistent with long-standing history for DE Progress and DE Carolinas in setting its North Carolina retail rates and is used by utilities in other states as well. (*Id.* at 703-4.)

Turning to the allocation of the Company's remaining distribution costs not assigned to the customer class, the Company used NCP allocators developed by taking the ratio of the non-simultaneous peak demands of the customers in each class whenever that peak occurred during the test period and comparing that to the sum of all customers' non-simultaneous peak demand. A number of different NCP allocators were developed to account for the different levels of the distribution system where customers may take service (substation and below, primary and below, secondary, etc.).

Witness Hager justified the Company's allocation of these costs in this manner by explaining that distribution facilities serve individual neighborhoods, rural areas, and commercial districts. (*Id.* at 701-11.) They do not function as a single integrated system in meeting system peak demand. Instead, the distribution system serving each neighborhood, rural area, or commercial district must be able to meet the peak demand in the area it serves whenever the peak occurs. Accordingly, contribution to NCP is the appropriate measure of determining customers' responsibility for these costs because it best measures the factors that drive investment to support that part of the system.

With regard to the allocation of energy related costs, witness Hager testified that these are costs that vary directly with the cost of producing, transmitting, and delivering electricity. (*Id.* at

701-11.) Examples of costs allocated on this basis are fuel costs and variable production costs incurred at generating stations. DE Progress' kWhs of generation and deliveries during the Test Period were used to allocate these variable costs. The kWh sales information was collected, and then adjusted for the level of losses attributable to each class and jurisdiction, in order to derive the level of kWhs at the generator attributable to that class or jurisdiction.

Witness Hager also addressed the Company's allocation of revenues associated with the EDIT rider to the customer classes based on the ADIT allocator. (*Id.* at 701-17.) She testified that this allocation methodology is reasonable and based on cost causation principles and because the EDIT amounts were previously part of ADIT as explained by Company witnesses Bateman and Panizza, this is consistent with how the amounts were allocated prior to the federal tax rate change and reasonably reflect how the benefits were created. (*Id.*)

Witness Hager testified that the Company's methodologies used to allocate its demand-related, energy-related and customer-related costs are reasonable and appropriate and that its COSS is a proper foundation for distributing costs among the jurisdictions and customer classes because it recognizes cost causation and distributes costs accordingly. (*Id.* at 701-17.) In addition, she verified that the COSS provides a proper basis for determining cost-based rates and is a major component of fair and equitable rate design. (*Id.* at 701-17 – 701-18.)

Vote Solar and SC NAACP et al., challenged the Company's proposal to rely upon the minimum system methodology to allocate costs to the customer class and establish the BFC. Witnesses Barnes and Wallach contend that the costs of the service drop and meter, meter reading, billing and collection and customer information and services are the only costs that should be allocated to the customer class and recovered via the BFC. (Tr. Vol. 3, p. 254-14; Tr. Vol. 5-1, p.779-6.) Witness Wallach relies upon the *Principles of Public Utility Rates* written by Dr. James

Bonbright to support his argument asserting that the text says that metering and billing expenses are "the most obvious examples" of customer costs.[62] (Tr. Vol. 3, p. 254-17.) However, Company witness Hager explained that witness Wallach failed to mention that the quoted text does not say these are the only costs. (Tr. Vol. 4, p. 703-8.)

Witness Barnes, also relying on *Principles of Public Utility Rates,* claims that the minimum system method is not generally accepted as an appropriate method for classifying system costs.[63] (Tr. Vol. 5-1, p. 779-12.) Again, witness Hager refutes the attempt to rely upon Dr. Bonbright by noting that while he recognizes the difficulty of determining the proper allocation for the minimum system costs, he concludes that the exclusion of minimum system costs from demand-related costs is on "much firmer ground" than its exclusion from customer costs.[64] (Tr. Vol. 4, p. 703-8.) Dr. Bonbright recognizes that utilities must allocate all costs among the classes of customers in a fully-distributed cost analysis.[65] Witness Hager argues that more importantly, the NARUC CAM,[66] that was developed after Dr. Bonbright's work, transitioned from the theoretical world of Dr. Bonbright to the reality of utilities' need to move from development of revenue requirements to rate structures and finds that and concludes that a portion of the distribution costs are customer-related. (*Id.* at 703-8 – 703-9.) Witness Hager further called the Commission's attention to the fact witness Barnes acknowledges that the CAM refers to the Minimum System Method as one method of classifying distribution costs. (*Id.* at 703-9.)

Witness Barnes refers to a statement on page 136 of the CAM that mentions an "unresolved argument" about distribution costs. (Tr. Vol. 5-1, p. 779-35-779-37.) As noted by witness Hager,

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[62] James C. Bonbright, *Principles of Public Utility Rates.* Columbia University Press (1961 edition), p. 311.
[63] Bonbright, pp. 348-349
[64] Bonbright, pp. 348.
[65] Bonbright, pp. 348-349.
[66] *Electric Utility Cost Allocation Manual*, National Association of Regulatory Utility Commissioners, January 1992.

it appears that the "unresolved argument" is between the two methods discussed in the CAM for allocating the distribution costs at issue both of which recognize that some portion of the distribution system is necessary to serve customers, regardless of whether the customers take any energy from the system. (Tr. Vol. 4, p. 703-9 – 703-10.) The quote acknowledges that there are distribution costs "usually identified as customer related." (*Id.* at 703-9.)

Witness Barnes acknowledged that the minimum system method is used in other states. (Docket No. 2018-319-E, Tr. Vol. 7, p. 1428 – 1431.) The parties stipulated to the inclusion of the cross examination of witness Barnes by opposing counsel and the questioning of witness Barnes by Commissioner Williams during the hearing in Commission Docket No. 2018-319-E into the record of this proceeding. (Tr. Vol. 5-1, p. 776.) During cross examination at the hearing in Docket No. 2018-319-E, he admitted that notwithstanding his reliance on a Connecticut law that prohibits the inclusion of the distribution costs at issue in this proceeding in utilities' BFCs, the Connecticut Public Utility Regulatory Authority ("PURA") in an order issued December 17, 2014, stated that it had routinely allowed the use of the minimum system approach to establish Connecticut Power & Light Company's BFCs. (Docket No. 2018-319-E, Tr. Vol. 7, p. 1428 - 1431.) He further admitted that after the Connecticut legislature passed the law in 2015, the PURA issued an order on April 18, 2018, in which the PURA continued using the minimum system methodology to allocate costs to the customer class.[67] (*Id.*) The Public Service Commission took judicial notice of these two Connecticut PURA orders. (*Id.*)

[67] *See Order,* Application of the Connecticut Light and Power Company d/b/a Eversource Energy to Amend its Rate Schedules, Docket No. 17-10-46, (April 18, 2018); Order, *Application of the Connecticut Light and Power Company to Amend its Rate Schedules,* Docket No. 14-05-06 (December 17, 2014).

Witness Barnes claims that "the minimum system method is based on the dubious premise that customers will pay to connect to the grid even if they do not intend to use any electricity." (Tr. Vol. 5-1, p. 779-33.) Company witness Hager challenged this argument asserting that the premise of the minimum system methodology is not that a customer would connect to an electric utility's system with no intention of ever using any of the utility's service; rather, the premise is that a customer connects to a utility's system because he intends to use the utility's service and that the utility' system will be able to deliver electricity to the customer's premise. (Tr. Vol. 4, p. 703-11.)

Mr. Barnes states that "a customer who has no demand for electricity would have no need to be connected to the distribution system" (Tr. Vol. 5-1, p. 779-33.) and witness Wallach states that one of the minimum system method's flaws is that it "implausibly assumes that a utility would incur costs to build a distribution grid to serve customers that have no load." (Tr. Vol. 3, p. 254-12.) The Company does not dispute that it would not build any facilities to serve a premise that has no load. (Tr. Vol. 4, p. 703-11.) Rather, witness Hager explains that when the owner of a premise asks the Company to connect the premise to the Company's electric grid the owner expects the premise to have load and that the electricity needed to serve the load will be delivered when the switch is flipped. (*Id.*) Witness Hager testified that in order for that to happen, the Company had to install some "minimum" amount of distribution facilities in addition to the service drop and meter. (*Id.* at 703-11 – 703-12.) Without that minimum system, there is no flow of electricity. Each customer "caused" some portion of the distribution system to be built. (*Id.* at 703-12.) That is what the minimum system method seeks to identify.

Witness Barnes argues that the Minimum System Method results in an unwarranted increase in the fixed BFC and a lower kwh rate than would otherwise be the case which results in the customer receiving an incorrect price signal. (Tr. Vol. 5-1, p. 779-23.) He argues that the distribution costs identified by the minimum system methodology are demanded-related not customer-related. (*Id.*)

Company witness Hager disputed this assertion explaining that the current rate structure is sending an incorrect price signal. (Tr. Vol. 4, p. 703-13.) The current rate structure with no distribution costs included in setting the BFC sends an erroneous price signal that implies that reducing energy and demand usage allows the Company to avoid a portion of the distribution system that in fact is not avoidable, i.e., the minimum system. She argues that the Minimum System Method eliminates an erroneous price signal that is otherwise present. (*Id.*)

Witness Hager explained in detail that the current rate structure was established based on a cost of service that did not include minimum system. (*Id.* at 703-4.) She testified that the Company is proposing the use of the minimum system concept at this time because of its increasing concern with the subsidization allowed in the existing rate structure and the importance of improving the price signal sent to customers through its rates. (*Id.* at 703-5.)

Over the past several years the Company has been increasingly concerned with the issue of cross-subsidization between customers. (*Id.*) Witness Hager offered the example of the impact of net metering on recovery of the Company's revenue requirement to demonstrate its concern and interest in this issue. (*Id.* at 703-6.) The Company asserts that net metering exacerbates the problem of customer cross-subsidization. (*Id.* at 711-4.)

Similar to and related to the Company's concern with increasing customer cross-subsidization, the Company is concerned with ensuring that the price signals sent by its rate structure properly aligns with cost causation. (*Id.* at 703-5.) Witness Hager explained that when a rate structure varies from cost causation, customers make decisions with inaccurate price signals and cause costs to be shifted for recovery from other customers within the rate class. (*Id.*) A rate with an inappropriately low BFC necessarily results in an inappropriately higher demand or energy rate. (*Id.* at 703-6.) When rates reflect cost causation, subsidization and shifting of cost responsibility are minimized and customers make prudent, economic decisions, including decisions with regards to investments in solar generation and energy efficiency. (*Id.*)

Company witness Hager testified that a net-metering customer with roof top solar can significantly reduce his purchase of kWhs from DE Progress. (*Id.*) However, the customer still relies on the Company to provide electricity to his heat pump or air conditioner on cloudy days and hot summer nights and to his heat pump or electric furnace on cold winter mornings to keep the house warm. (*Id.*) If DE Progress is dependent upon its kWh rate revenues to recover all of its distribution costs, that customer is not paying a fair share of the cost of the distribution facilities needed to serve the customer. The costs are borne, once again, by all other customers. That is not fair to other customers.

As mentioned earlier, the parties stipulated to the inclusion of the cross examination of witness Barnes by opposing counsel and the questioning of witness Barnes by Commissioner Williams during the hearing in Commission Docket No. 2018-319-E into the record of this proceeding. (Tr. Vol. 5-1, p. 776.) During that hearing witness Barnes was cross examined and questioned on the issue of recovering fixed distribution costs through a kWh rate and the result when customers through DSM or EE or behind-the-meter solar generation reduce their purchases of kWhs from the Company. (Docket No. 2018-319-E, Tr. Vol. 7, p. 1435.) Witness Barnes admitted that the distribution costs in question consist of poles, conductors, transformers and conduit. (*Id.* at 1421-23.) He agreed that these are long-lived assets that last for decades. (*Id.*) He further agreed that these assets are not consumed when used the way fuel is consumed. (*Id.* at

1422.) Witness Barnes agreed that in the absence of growth in kWh sales by DE Carolinas to other customers to offset the sales lost to DSM, EE or behind-the-meter solar generation, DE Carolinas must further increase its kWh rate to recover its distribution fixed costs. DE Carolinas asserted that this results in the remaining customer body subsidizing the DSM, EE and solar customers. (*Id.* at 1434 – 1439, 1444 – 445.) This testimony from Docket No. 2018-319-E for DE Carolinas equally applies to DE Progress.

Witness Barnes observed that the Company used the minimum system methodology in its COSS to determine the existing rates of return by customer class and rate schedule. (Tr. Vol. 5-1, p. 779-39.) He asserts that the variance from the average rate of return for the residential class under a no minimum system assumption is smaller than with a minimum system assumption. (*Id.*) He then concludes that the no minimum system assumption more accurately assigns class cost responsibility. (*Id.* at 779-39 – 779-40.) Witness Hager disagreed arguing that there is no basis for such a conclusion. She explained that just because the class rate of return is higher when the minimum system approach is not used that does not indicate using the minimum system is incorrect, rather it simply shows that changing the input numbers changes the result. (Tr. Vol. 4, p. 703-13.)

Witness Barnes further criticizes the minimum system approach asserting that the Company used the smallest equipment customarily installed instead of the smallest equipment that could be installed. (Tr. Vol. 5-1, p. 779-29.) Company witness Hager disagreed and explained that the methodology used by the Company is consistent with the CAM for the minimum size method, what is typically called the Minimum System Method. (Tr. Vol. 4, p. 703-14.) For each FERC account included in the minimum system study, the CAM manual instructs the utility to "determine the average installed book cost of the minimum [equipment] currently being installed."[68]

Witness Barnes further argues the minimum system is flawed because it assumes a hypothetical minimum system which he claims would never be built today because of other available alternatives such as a combination solar panel and battery. (Tr. Vol. 5-1, p. 779-31.) Witness Hager testified that regardless of whether witness Barnes is correct, the task before the Commission is to allocate the existing, embedded costs the Company has incurred to provide a minimum system to serve customers. (Tr. Vol. 4, p. 703-14.) She claims that the costs of a solar panel and a battery are not relevant. (*Id.*)

Witness Wallach states that one of the "fundamental flaws" in the minimum system method is that it "erroneously assumes that the minimum system would consist of the same number of units (e.g., number of poles, feet of conductors) as the actual system." (Tr. Vol. 3, p. 254-11.) Witness Hager challenged this assertion. (Tr. Vol. 4, p. 703-15.) She testified that the Company's minimum system study does not assume the same number of poles and feet of conductor. (*Id.*) Instead, she said the cost for a "skeleton" mile of system with the minimum number of poles and feet of conductor was developed and multiplied by the miles of line. (*Id.*) This assumption results in a lower minimum system cost than assuming the same number of poles and lines. (*Id.*)

Witness Barnes discussed the need to consider the marginal cost of connecting customers to the grid and how that affects the validity of the minimum system approach. (Tr. Vol. 5-1, p. 779-37.) Witness Hager testified that marginal costs are not relevant to the creation of a COSS and the allocation of costs because the issue in cost of service is allocating existing embedded

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[68] NARUC CAM, pp. 91-92.

costs. (Tr. Vol. 4, p. 703-10.) She explained that the Company's distribution system is constructed to connect generation sources to individual customers. (*Id.* All customers benefit from the existence of the system. It would be unfair to existing customers if DE Progress only considered the marginal cost of serving the next customer and did not charge new customers for a pro rata share of the existing system.

Witnesses Wallach and Barnes take issue with the Company including AMI meters costs in the customer-related class. They argue that only the cost of a basic meter should be included in the customer-related class. (Tr. Vol. 3, p.254-18.) Witness Hager addressed this assertion by explaining that AMI meters are now the standard installation configuration for most all customers and, as such, are appropriately classified as customer-related costs. (Tr. Vol. 4, p. 703-16.)

Finally, witness Wallach argues that uncollectible costs should not be allocated to the customer-related class because they allegedly vary with revenues and therefore with usage. (Tr. Vol. 3, p. 254-21.) Witness Wallach offered no support for this assertion. Witness Hager explained that these costs are properly accounted for and charged to the FERC Customer Accounting accounts. She concluded that this continues to be a reasonable assumption. (Tr. Vol. 4, p. 703-16.)

The ORS did not challenge the Company's COSS, allocation methodology or the minimum system approach for allocation purposes.

The Commission finds the testimony of the Company and the ORS persuasive on this issue and concludes that the Company's methodologies used to allocate its demand-related, energy-related and customer-related costs are reasonable and appropriate and that its COSS is a proper foundation for distributing costs among the jurisdictions and customer classes because it recognizes cost causation and distributes costs accordingly. The Commission also notes that nothing in this finding regarding overall class allocation requires the Commission to follow Minimum System for rate design, particularly for the BFC, a separate issue addressed in Evidence for Findings and Conclusions Nos. 42-46 of this Order.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NOS. 42-46

The evidence in support of the findings of fact are found in the verified Application, Nucor Stipulation, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

Company witness Wheeler testified that the rates DE Progress proposes in its Application reflect appropriate rate making principles and result in an equitable basis for recovery of the Company's revenue requirements across and within its various customer classes and rate schedules. (Tr. Vol. 4, p. 709-3.) Application Exhibit A presents the Company's current tariffs that are requested to be revised in this proceeding. Application Exhibit B provides the proposed tariffs changes. Application Exhibit C presents the Company's current tariffs, highlighting all proposed changes to rates and terms. Under the proposed rates, an average monthly bill for a residential customer using 1,000 kWh will increase from $124.10 to $142.00 or 14.4 percent. (*Id.* at 709-13.) If the current Fixed Monthly Rider 39 Charge applicable to residential customers of $0.72 is included, the bill increases from $124.82 to $142.72 or 14.3 percent. (*Id.*)

Witness Wheeler explained that he used the cost of service study as a major component for the rate design along with witness Bateman's proposed change in revenue requirement for each rate class.[69] (*Id.* at 709-7.) He also reviewed the Company's load research data to examine

[69] The Company proposes to allocate its requested rate increase to the customer classes on the basis of rate base and then make an adjustment to move each class 25 percent closer to its respective cost of service. (*See* Hearing Ex. 14 (Bateman Exhibit 2). (Tr. 320-9 – 320-10.) No party contested the Company's proposed rate spread at its proposed revenue requirement. However, if the Commission determines that a revenue requirement less than the revenue requirement proposed by the Company is appropriate, Walmart witness Chriss testified that the Commission should

customer usage characteristics and to determine relationships between energy and demand, both on a coincident peak and non-coincident peak basis that might prove pertinent to the design of the Company's rates. (*Id.*) He testified that he used marginal cost information to assess the merits of seasonal and time-of-use pricing relationships that are appropriate to be considered in the final rate design. (*Id.*) Witness Wheeler said marginal cost data supports a reduced emphasis on on-peak energy rates as the difference between on-peak and off-peak marginal energy cost has narrowed over the past years and that it no longer supports a substantial emphasis on summer pricing. (*Id.*) He explained that as noted in the Company's 2018 Integrated Resource Plan, system load data indicates winter peak demand should also be considered. (*Id.*) He then testified that in designing DE Progress' proposed rates he also considered the Company's current rates and their structure, impacts upon customers, simplicity of the rate design, administrative complexity, marginal and embedded price signals, and rate and revenue stability. (*Id.* at 709-8.)

Witness Wheeler testified that the first step in rate design is to determine each rate class's total proposed change in revenue requirement. (*Id.*) Then the rate schedules and riders within the five major rate classes: residential; small general service; medium general service; large general service; and various outdoor lighting schedules are designed to sum to the total proposed change in the revenue target for that respective rate class. He explained that there are three basic cost categories: customer cost; demand cost; and energy cost. (*Id.*) Witness Wheeler testified that efficient rate design considers and reflects the component costs within each category. Cost

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take steps to further reduce the interclass subsidy and apply 50 percent of the overall revenue reduction to those customer classes with an indexed rate of return above 1.0, except that in no event should a subsidizing rate class be moved to a subsidized position. (Tr. Vol 5-2, p. 992-18). He added that the remaining 50 percent of the overall revenue reduction should be evenly applied to reduce the proposed increases for all rate classes on an equal percentage basis. (*Id.*) Based on the evidence presented in this case concerning gradualism, we find that the Company's proposal to allocate the revenue increase among the customer classes is more appropriate.

causation is a basic tenet of sound ratemaking that assigns cost for recovery in rates from the determinants that most influence the cost to be incurred. He said the unit cost study indicates it is appropriate to raise the monthly BFC to better reflect all customer-related costs. (*Id.*) Witness Wheeler asserted that to do otherwise results in customer cross-subsidization. (*Id.* at 709-9.) As recommended and agreed to in a settlement in DE Progress' 2016 rate case, the Company proposes that the BFC for all rate classes be increased to more fully recover the customer-related cost incurred to serve these customer groups. (*Id.*) A comparison of the current and proposed Basic Facilities Charges for each rate class was provided in Hearing Ex. 27 (Wheeler Exhibit No. 2).

Witness Wheeler explained that the unit cost study from the cost of service study also provides demand-related unit costs that are directionally important in establishing cost-based demand charges that minimize cross-subsidization within a rate class, as well as signal to these customers what is the cost impact of their demand. (*Id.*) The final component cost is the energy component which enables the total rate schedule to achieve its revenue target and signals energy cost impacts.

Witness Wheeler observed that prior to the Company's 2016 rate case the Company's rates had not been modified since 1988; therefore, some rates had drifted farther from unit costs than others. (*Id.*) In the 2016 rate case, some progress was made toward aligning rates more closely with the associated underlying costs but some difference remained. (*Id.*) In this case the Company proposes to further reduce this difference in order to move towards a more equitable pricing structure. (*Id.* at 709-9 – 709-10.) Witness Wheeler testified that this approach minimizes rate migration concerns as the pricing reflected in each rate schedule moves towards the requested rate class rate of return. (*Id.* at 710.) In most cases, the Company proposed that the percent change in rates for all schedules within the rate class be increased by the same percentage; however, an approximately 10 percent higher increase was proposed in schedules exhibiting a significantly lower return than the rate class and a 15 percent higher increase was proposed for schedules that are no longer available to new participants. (*Id.*) This higher increase percentage for frozen tariffs continues the Company's effort to phase-out frozen schedules by incenting migration to other schedules as standard tariffs result in lower annual bills.

Witness Wheeler explained that DE Progress is not proposing any new peak time pricing or dynamic rate designs at this time. He said DE Progress continues to review and analyze rate designs that offer customers opportunities to respond to real time price signals to achieve a lower cost for electric service. (*Id.*) He noted that Company witness Hunsicker testified that the Company is upgrading its customer information billing system infrastructure to better support these types of designs. (*Id.*) He said that metering installed for the majority of current customers doesn't provide the interval level data that is required to bill these innovative designs. (*Id.*) Company witness Schneider testified that the Company began deployment of an AMI in May 2018 that offers the necessary level of meter sophistication to support such new rate designs. (*Id.* at 709-11.)

Witness Wheeler emphasized that the Company presently offers time-of-use rate designs to all customer classes to encourage load shifting and also offers several DSM programs to control customer appliances to aid in reducing system peak demands. (*Id.*) The Residential EnergyWise program controls customer air conditioning system wide. The Business EnergyWise program controls air conditioning for nonresidential customers. These programs target load reductions during summer peak periods with minimal inconvenience to the participant. Witness Wheeler said the advantage of these types of DSM programs versus a pricing option is that the customer doesn't have to make a prompt decision with respect to participation thereby ensuring a more predictable result. (*Id.*)

Regarding the Company's residential rates, witness Wheeler testified that Residential Service Schedule RES will continue to be the basic service schedule available to all residential customers. (*Id.* at 709-14.) The Company proposes to increase the BFC in Schedule RES to reflect the customer-related cost of serving these customers. (*Id.*) The Company originally requested that the monthly BFC be increased from $9.06 to $29.00 to recover the full amount of customer-related cost identified in the unit cost study for the residential rate class. The Company asserts that approval of the requested rate will reduce cross-subsidization of billing for low usage customers by other residential ratepayers. (*Id.*) The Schedule RES kWh energy rates are adjusted to achieve the resultant revenue target net of the facilities charge. The current energy block structure that offers a 1 cent per kWh lower rate for usage in excess of 800 kWh during non-summer billing months is reduced to 0.5 cents per kWh to recognize a growing emphasis on the winter peak for system planning purposes in the Company's Integrated Resource Plan. This reduces the current emphasis on summer rates which continue to pay the higher first block rate for all usage.

The Company is proposing to adjust the rates in Residential Service Time-of-Use Schedule R-TOUD to achieve a slightly higher increase than recommended for Schedule RES because the R-TOUD return is only slightly less than RES. (*Id.* at 709-15.) The BFC matches Schedule RES plus a rate differential of $2.85 to recover the additional cost incurred for TOU meter-related costs, matching the current rate design. (*Id.*) The demand and energy prices in R-TOUD are adjusted by the same percentage to achieve the revenue target. Witness Wheeler explained that differences between the cost of on-peak and off-peak energy and seasonal costs continue to narrow and therefore DE Progress proposes that the differential between summer and non-summer demand rates be reduced from the current 30 percent to 20 percent. (*Id.* at 709-16.) Finally, DE Progress proposes that the differential between on-peak and off-peak energy rates be reduced from the current 22 percent to 15 percent to reflect more current marginal cost relationships. (*Id.*)

Regarding the Company's non-residential rates, the small general service rate class includes all nonresidential customers with demand requirements below 30 kW. (*Id.*) Tariffs within the class include Small General Service Schedule SGS, Small General Service Time-of-Use SGS-TOU and General Service Schedule GS. (*Id.*) The Company proposes to increase the BFC to reflect the customer-related cost of serving these customers. (*Id.*) Witness Wheeler testified that the unit cost study justifies a Basic Facilities Charge of $29.06 per month and DE Progress proposes that the charge be increased from $9.91 to $29.00 for all SGS schedules. (*Id.*) The Company proposes to increase the additional monthly charge for three-phase service from $6.00 to $6.50 to reflect the updated cost of additional facilities required for this higher level of service. (*Id.*at 709-16 – 709-17.) The updated rate would apply to all schedules with a separate three-phase charge. The current kWh energy block structure is retained with the second block being 28 percent less than the block 1 kWh energy rate. (*Id.*at 709-17.) SGS energy rates are proposed to be adjusted to recover the requested revenue increase.

With regard to Rate Schedule GS, witness Wheeler explained that it has not been available to a new applicant since January 1, 1989 and currently serves 95 customers. (*Id.*) These customers typically have demands in excess of 30 kW with load factors below 10 percent, and would realize a substantial increase in billing if migrated to a schedule with demand rates. As a result, consistent with the Company's past practice for frozen schedules, DE Progress proposes that the current rate structure be retained, but that the schedule's rates be increased by approximately 15 percent more than the SGS rate class to encourage customers to migrate to a standard tariff. (*Id.*) The current percentage differential in the three declining energy blocks is retained and is adjusted to recover the requested revenue increase.

With regard to Rate Schedule SGS-TOU, witness Wheeler testified that it serves both SGS and MGS class customers. (*Id.*) Since the smaller SGS-TOU customers within the SGS rate class comprise less than 5 percent of the schedule population from a kWh sales perspective, the Company proposes to adjust SGS-TOU rates using the MGS class revenue change. (*Id.* at 709-17 – 709-18.)

The Company's proposed rate changes to Schedule SGS-TOU-CLR which applies primarily to cable television amplifiers that exhibit a constant electrical requirement include the same monthly BFC of $29.00 as the SGS class schedules with an energy rate necessary to recover the allocated revenue requirement. (*Id.* at 709-18.)

The Company's medium general service rate class includes all nonresidential customers with demand requirements from 30 kW to 1,000 kW. (*Id.*) Tariffs within the class include Medium General Service Schedule MGS, Small General Service Time-of-Use Schedule SGS-TOU, Small General Service (Thermal Energy Storage) Schedule SGS-TES, Church and School Service Schedule CSE and Church and School Service Schedule CSG. The Company proposes to increase the BFC to reflect the customer-related cost of serving these customers. Witness Wheeler asserts that the Company's unit cost study justifies a BFC of $40.78 per month; therefore, DE Progress proposes that the charge be increased from $17.17 to $40.03 per month for single-phase service (or $46.53 if the customer requests three-phase service). (*Id.* at 709-19.) After adjusting the BFC, the kW demand and kWh energy rates are proposed to be increased by the same percentage to achieve the requested revenue. There are no other changes requested to this basic rate form.

For Rate Schedule SGS-TOU the Company proposes to increase the BFC from $23.17 to $46.53, which is consistent with the current design to reflect the MGS Facilities Charge of $40.03 plus the $6.50 rate applicable to three-phase service. (*Id.*) The proposed on-peak demand rate reduces the current 28 percent relationship between on-peak and off-peak rates to 20 percent during the months of June through September. The Company requests that the difference between on-peak and off-peak energy rates be reduced from the current 26 percent to a 20 percent pricing premium over the off-peak energy rate. (*Id.*) Witness Wheeler explained that the Company realizes a lower than class average return under Schedule SGS-TOU; therefore, the SGS-TOU rates are proposed to be increased by 10 percent more than the increase to Schedule MGS to better match the cost of serving these customers. (*Id.*) The on-peak and off-peak kWh energy and demand rates are adjusted by a fixed percentage to recover the requested revenue requirement. (*Id.*) The off-peak excess kW charge is proposed to be increased from $2.95 per kW to $3.30 based upon the MGS distribution-related unit cost study to better ensure that customers using electricity primarily during off-peak hours pay the cost of distribution facilities necessary to deliver electricity to the customer. (*Id.* at 709-19 – 709—20.)

For Rate Schedule SGS-TES the Company proposes to increase the BFC to $46.53, which matches the SGS-TOU rate design. (*Id.* at 709-20.) The energy and demand charges in Schedule SGS-TES are adjusted by the same percentage as applied to energy and demand rates under Schedule MGS.

Turning to frozen Rate Schedules CSE and CSG, the Company proposes to increase their BFCs to $40.03 to match the BFC of the MGS class schedules with an energy rate necessary to recover the allocated revenue requirement. (*Id.*) Consistent with the Company's past practice for frozen schedules, the Company requests to increase the rates of these two schedules 15 percent more than Schedule MGS to encourage migration to a standard tariff. (*Id.*)

The Company proposes to continue to offer a uniform minimum bill provision under schedules SGS-TOU, SGS-TES, GS, CSE and CSG and increase the minimum bill energy rate to include the current DSM and EE rate applicable under this schedule. (*Id.* at 709-21.)

With regard to the Company's Large General Service rate class which includes all nonresidential customers with demand requirements of 1,000 kW or greater, it includes the Large General Service Schedule LGS, the Large General Service Time-of-Use Schedule LGS-TOU, the Large General Service Curtailable Service Schedule LGS-CUR-TOU, and the Large General Service (Real Time Pricing) Schedule LGS-RTP.

The Company proposes to increase the BFCs for the LGS class from $98.00 to $195.00 to better reflect the customer-related cost identified in the Company's customer-related unit cost study. (*Id.* at 709-22.) The Company increased the kW demand and kWh energy rates by the same percentage to achieve the requested revenue requirement.

Turning to the individual LGS rate schedules, for LGS-TOU the Company proposes to increase on-peak demand rates by 50 percent of the energy rate adjustment because they already approximate the LGS class demand-related unit cost. The off-peak excess kW charge is decreased from $1.25 per kW to $0.89 to better ensure that customers pay the cost of facilities necessary to deliver electricity to them. (*Id.* at 709-23.) The kWh energy rates are adjusted to reflect the proposed increase in revenue, retaining the current half cent per kWh differential between the on-peak and off-peak energy rates. The increased energy rates reflect an emphasis on on-peak rates when fuel costs are higher.

With regard to the LGS-RTP rate schedule the Company proposes to increase Administration Charge from $142.00 per month to $160.00 per month to reflect the ongoing cost incurred to support the development of daily hourly rates and other cost required to support this unique rate design. (*Id.* at 709-24.) The Facilities Demand Charges are adjusted based upon the Company's unit cost study to more accurately recover the cost of delivering electricity to the customer's site. The tax factor applicable to the hourly rate is also revised to recover current gross receipts taxes and the current South Carolina Regulatory Fee since these incremental costs are incurred with the sale of electricity. In the Company's Application, the Company proposed to increase all LGS-CUR-TOU rates by the requested percentage increase in retail rates without any change to the basic design structure. However, on March 29, 2019 the Company and Nucor Steel filed the Nucor Stipulation (Hearing Ex. 35) in which the Company agreed to limit the rate increase for the LGS-CUR-TOU rate schedule to the final Commission approved LGS class percentage increase. No other party offered any evidence regarding the appropriate increase for the LGS-CUR-TOU schedule. The Commission finds the rate increase for the rate schedule set forth in the Nucor Stipulation (Hearing Ex. 35) is reasonable given that the Company and the only customer subscribing to this schedule who participated in this proceeding agree that it is in the public interest.

The Company proposes to adjust the transformation-ownership discount in the LGS class schedules to reflect the results of the Company's unit cost study regarding the costs the Company avoids when a customer owns the facilities that allow the Company to avoid transmission-to-distribution and distribution-to-secondary transformations. (Tr. Vol. 4, p. 709-23 – 709-24.)

For the Seasonal and Intermittent Service Schedule SI, because subscribers to this schedule have a load requirement similar to MGS class customers, the Company proposes to increase the

BFC to $40.03 to match the MGS Schedule. (*Id.* at 709-25.) The Customer Seasonal Charge in Schedule SI seeks to recover approximately 3 months of the Basic Facilities Charge because no bill is rendered when service is not used during the billing month. Accordingly, the Company adjusted the Customer Seasonal Charge from $32.25 to $75.14 to reflect the proposed increase in the BFC. (*Id.*) The kWh energy rates were adjusted by a fixed percentage to achieve the requested change in revenue for the rate class.

Turning to the Company's Sports Field Lighting Service Schedule SFLS, because customers on this rate have demands of 30 kW or greater, similar to MGS class customers, the Company proposed a BFC of $40.03. (*Id.*) The three-phase charge is proposed to be increased from $6.00 to $6.50, consistent with changes to other schedules. (*Id.* at 709-25 – 709-26.) The energy and demand rates were then increased by a fixed percentage to achieve the Company's targeted change in revenue requirement. The Company requested to increase the charge for disconnection of service after less than one-full month of service from $15 to $17 to match the Service Charge requested in the Service Regulations for a similar activity. (*Id.*) The Company's traffic signal service rate class includes the Traffic Signal Service (Metered) Schedule TFS and Traffic Signal Service Schedule TSS, a schedule that offers unmetered electricity based upon the signal configuration. Although there are no current participants, witness Wheeler explained that TFS customers should have a similar service requirement as the SGS class; therefore, the Company requested that the Schedule TFS BFC and the TSS Minimum Bill Facilities Charge both increased to match the proposed SGS BFC of $29.00. (*Id.*) The Company proposed to adjust the TSS fixture rates by a fixed percentage to achieve the requested revenue requirement. (*Id.*) The Schedule TFS energy rate was adjusted by the same percentage change as was used for the Schedule SGS energy rates to mitigate the expected revenue gain from the BFC.

The Company provides outdoor lighting service under Area Lighting Service Schedule ALS, Street Lighting Service Schedule SLS and Street Lighting Service (Residential Subdivisions) Schedule SLR. Witness Wheeler testified that the Company has a long-term goal of offering the same monthly rate for the same lighting product to all customers regardless of whether the fixture is installed on a public street or private property. (*Id.* at 709-27.) He explained that the Company's installation and maintenance costs do not vary based upon location; therefore, the same lighting product should have the same monthly rate in all schedules. (*Id.*) The Company's existing tariffs reflect this pricing approach with respect to LED fixtures and many poles/posts. The rates requested in the proposed outdoor lighting schedules reflect an adjustment to achieve a combined outdoor lighting revenue target and seek to reduce or eliminate the difference between the monthly rates in the Area and Street Lighting Service Schedules for similar fixtures and poles/posts. Because the current SLS Class has a significantly lower return than realized under Schedule ALS, the Company recommended a higher increase for Schedule SLS and SLR. (*Id.*)

Witness Wheeler testified that the proposed Schedule SLS rates match the proposed Schedule ALS rates with the following exceptions: (1) the system metal pole is only available under Schedule SLS and is therefore increased by the same percentage as Schedule ALS pole rates; (2) wood poles and metal/fiberglass pole/posts comprise 84 percent of all installed SLS poles/posts and are currently priced lower than comparable ALS poles/posts; (3) a gradual approach to adjusting these SLS pole/post rates is recommended by the Company; therefore, these SLS rates are recommended to only increase by the same percentage as ALS poles/posts, and (4) the Decorative Square Metal pole rates will not match, but both rates are increased by the pole percentage. (*Id.* at 709-28.) This approach aids in mitigating the impact of uniform pricing on

SLS customers who will realize a larger increase than ALS customers under the Company's proposed rate design.

The Company proposed several rate changes for the SLS rate class. (*Id.*) Witness Wheeler explained that current rates for LED fixtures realize a lower contribution to class costs than other fixtures therefore a higher increase in rates was merited. (*Id.*) In addition, he asserted that pole/post rates are significantly less than the current costs of providing these facilities; therefore, they should also be increased by a larger amount than fixture rates. (*Id.* at 709-28 – 709-29.) The Company proposed to increase all ALS fixtures rates by a fixed percentage to achieve the revenue target with the pole/post rates and LED fixture rates being increased by twice the percentage increase in fixture rates to better reflect marginal cost. (*Id.* at 709-29.)

Because Rate Schedule SLR is included in the SLS class; the Company's proposes to increase all rates by the same percentage to realize the same percentage increase in revenues under SLR as realized for Schedule SLS. (*Id.*)

The Company is requesting that High Pressure Sodium Vapor ("HPS vapor") fixtures no longer be available for new installations to continue the Company's emphasis on LED technology for all new installations. (*Id.*) Witness Wheeler asserted that LED technology offers improved energy efficient, provides excellent color and light quality, and is expected to have lower maintenance costs. (*Id.*) To aid in this transition, HPS vapor will continue to be available to sites with contiguous HPS lighting. Upon failure of an HPS ballast or fixture, it will be replaced at no charge to the customer with a comparable LED fixture, as identified in a table included in each lighting schedule.

For ALS rate schedule rates, the Company requests that all fixtures rates and the monthly underground charge be increased by a fixed percentage to achieve the revenue requirement target.

(*Id.* at 709-30.) The Company proposed to increase the contract term for area lights installed on existing distribution poles and served with overhead distribution lines from one to three years to reduce the Company's exposure to short-term lighting installations where the Company may not fully recover its installation and removal cost. (*Id.*)

The Company proposed to retitle its Street Light Service Regulations as "Outdoor Lighting Service Regulations" and apply them to both street and area light installations. (*Id.*) As a result, the same basic practices and procedures will apply to all outdoor lighting installations.

With regard to service riders, witness Wheeler testified that the Company offers several service riders that require customers to curtail their electrical usage upon notification from the Company to aid in reducing load during hours with generation constraints. (*Id.* at 709-31.) These Riders include Large Load Curtailable Rider LLC, Dispatched Power Rider No. 68, Incremental Power Service Rider IPS and Supplementary and Non-Firm Standby Service Rider NFS. The Customer Charge identified in each of these riders recovers the cost associated with a customer notification system ("CNS") that is necessary to alert customers of curtailment events. The Company proposes to increase this charge from $16.80 to $50.00 to recover the current cost of notification technologies to support e-mail, pagers, text messaging and telephone communications to multiple customer recipients to alert participants of impending curtailment events. (*Id.* at 709-31 – 709-32.)

Regarding changes to the individual riders, for Large Load Curtailable Rider; the Company requested to decrease the Level 1 Capacity Buy-Through Rate from $5.35 to $4.60 per kW of non-firm demand to better reflect the current avoided cost benefit. (*Id.* at 709-32.) Witness Wheeler testified that the cost basis for the Discount Credit reflects the Company's 5-year levelized marginal generation cost and annual fuel credit calculated pursuant to the methodology reflected in DE Progress' current avoided cost rates approved effective July 2016 in Docket No. 1995-1195-E. (*Id.*) Correspondingly, the charge for the use of Premium Demand during a Level 1 and Level 2 Capacity Curtailment is reduced to $2.30 per kWh and $45.00 per kW, respectively. (*Id.*)

For the Supplementary and Non-Firm Standby Service Rider and the Supplementary and Firm Standby Service Rider the Non-Firm Standby Service Delivery Charges are adjusted to reflect the unit cost of service for service from distribution and transmission facilities and the Generation Reservation and Standby Service Delivery Charges are both revised to reflect current cost of service in the Supplementary and Firm Standby Service Rider.

Finally, the Company proposes to update the rates in the Meter-Related Optional Programs Rider (TotalMeter and NonStandard Metering) to better reflect current cost estimates. (*Id.* at 709-33.)

Witness Wheeler testified that the Company is proposing a new EDIT Rider. (*Id.* at 709-35.) Company witness Bateman explained that the Company will credit customers through a rider for certain benefits resulting from The Federal Tax Cuts and Jobs Act and the North Carolina Income Tax Rates in House Bill 989, An Act to Simplify the North Carolina Tax Structure and to Reduce Individual and Business Tax Rates. (*Id.*) The Year 1 revenue impact is included in the revenue increase target used to establish proposed rates in this proceeding. The EDIT Rider Year 1 rates will expire after 12 months and, upon Commission approval, will be replaced at that time by the Year 2 rate credit following the approach outlined in witness Bateman's testimony. (*Id.*) The Year 1 revenue requirement by rate class was provided by witness Bateman and was allocated as shown in Bateman Exhibit No. 2. (*Id.* at 709-36.) The revenue requirement was then divided by test year billed sales for each rate class to establish class rates. The derivation of the credit rate applicable to each rate class is provided on Wheeler Exhibit No. 7. (*Id.*)

As discussed herein in Evidence for Findings and Conclusions Nos. 50-51, in the Nucor Stipulation, the parties agreed to revise the Company's EDIT rider as follows: 1) All deferred revenues from January 2018 through May 2019, related to the reduction in the federal tax rate, shall be returned to ratepayers over three years (instead of five years as originally proposed the Company's Application); and 2) the amount of DERP deferred balances to be offset under the Rider shall be reduced to $6 million (instead of $12.66 million as originally proposed in the Company's Application). The parties asserted that these changes will return excess deferred income tax-related dollars to customers more quickly and there will be a larger credit to customers under the EDIT rider in the first three years of the rate increase compared to the EDIT rider as proposed in the Application while also offsetting nearly half of the DERP deferred balances. No other party commented upon or objected to the stipulation on this matter. The Commission finds that the revenue requirement under the EDIT rider as modified by the stipulation is in the best interest of DE Progress' customers and is in the public interest for the reasons explained by Nucor and the Company.

In addition to revising many of the Company's rate schedules the Company proposes to change many of its Service Regulations. Witness Wheeler asserted that these changes are designed to better reflect current cost studies. (Tr. Vol. 4, p. 709-13.) These changes include:

1. The Service Charge is requested to be increased from $15.00 to $17.00 while the Landlord Service Charge is requested to be increased from $4.50 to $5.35.
2. The Reconnect Charge is requested to be increased from the current rate of $15.00 to $19.00.
3. The monthly facilities charge associated with Extra Facilities is requested to be reduced from 1.1 percent to 1.0 percent under the non-contributory option with the

> rate applicable under the contributory option being unchanged at 0.3 percent. This same change is proposed in the monthly facilities charge applicable to interconnection facilities installed pursuant to the Terms and Conditions for the Purchase of Electric Power under a Purchase Power Agreement executed under the Purchased Power Schedule PP.

(*Id.* at 709-13 – 709-14.) DE Progress proposes to implement its proposed tariff and service regulations changes by filing with the Commission revised tariffs and service regulations consistent with the rates and charges approved in the Commission's final order in this case. These compliance filings would become effective on the implementation date set by the Commission unless the Commission suspends the rates or takes other action to prevent implementation of the rates.

In support of his testimony witness Wheeler filed the following exhibits (as part of composite Hearing Ex. 27):

- Wheeler Exhibit No. 1 provides the South Carolina Retail Electric Rate Schedules, Riders, Service Regulations and other tariffs DE Progress proposes to be revised and effective for service rendered on and after June 1, 2019, as required by 26 S.C. Code Ann. Reg. 103-823 (Supp. 2016). This exhibit is the same as Exhibit B to the Company's Application in this docket.
- Wheeler Exhibit No. 2 illustrates the Basic Facilities Charges for the major customer classes.
- Wheeler Exhibit No. 3 provides revenues at current and proposed rates under the proposed rate design. Revenues are also shown including DSM and EE clause revenues to more clearly identify the full percentage impact on customer bills.

- Wheeler Exhibit No. 4 provides the consolidated class impacts from the proposed increase.
- Wheeler Exhibit No. 5 shows bill comparisons between the Company's present and proposed rates. Consistent with DE Progress' presentation of adjustment clause rates within its schedules, these comparisons include the current DSM and EE rates approved in Docket No. 2017-245-E in both the current and proposed bills and represent the customer's full bill after inclusion of the requested rates.
- Wheeler Exhibit No. 6 related to the Company's Grid Improvement Plan which will not be addressed in this proceeding.
- Wheeler Exhibit No. 7 provides the derivation of Excess Deferred Income Tax Rider EDIT that describes rate credits associated with changes in federal and North Carolina corporate income tax rates.

Basic Facilities Charge

ORS witness Seaman-Huynh, Vote Solar witness, Barnes, and SC NAACP et al. witnesses Wallach and Howat oppose the Company's proposed reliance upon the minimum system methodology to identify customer class costs and the resulting increase in the residential BFC for a variety of reasons. While the ORS does not oppose the use of the minimum system approach for allocating costs to the customer class, ORS witness Seaman-Huynh recommends that the residential BFC should recover no more than 25% of the approved revenue increase assigned to that customer class in order to mitigate the magnitude of the increase in the residential BFC or $11.78 based upon the ORS' recommended revenue increase. (Tr. Vol. 6, p. 1099-10.) SC NAACP et al. witness Howat argued that the proposed BFC is higher than other utilities and is therefore inappropriate. (Tr. Vol. 3, p. 279-9 – 279-10.) Vote Solar witness Barnes and SC

NAACP et al. witness Wallach assert that an increase in the BFC discourages distributed generation and energy efficiency. (Tr. Vol. 3, p. 254-6; Tr. Vol. 5-1, p. 779-5.) Witness Barnes argues that the current $9.06 BFC should be retained (Tr. Vol. 5-1, p. 779-49), while SC NAACP witnesses Howat and Wallach argue that the increase in the BFC should be limited to $9.23, the amount calculated excluding minimum system related cost and certain other adjustments. (Tr. Vol. 3, p. 254-6.) Witness Howat asserts that the proposed BFC disproportionately harms the low-income customers alleging that they are in general, low-usage customers whose monthly bills will rise more than customers with average or above average usage. Witnesses Wallach and Barnes allege that the costs identified by the minimum system methodology are not customer-related costs and should not be included in the BFC. (*Id.* at 279-12.)

Company witness Wheeler rebutted all of these intervenors' challenges to the Company's BFC. He explained that rates should reflect cost causation in order to minimize subsidization of customers within the rate class. (Tr. Vol. 3, p. 711-3. He argued that customer-related costs are unaffected by changes in customer consumption and therefore should be paid by all customers, regardless of their consumption. (*Id.*)

Witness Wheeler testified that residential customer-related costs not recovered in the BFC are shifted to energy rates causing high-usage customers to subsidize lower-usage customers. (*Id.*) Failing to properly recover customer-related costs via a fixed monthly charge provides an inappropriate price signal to customers and fails to adequately reflect cost causation. (*Id.* at 711-3 – 711-4.) He explained that shifting customer-related costs to the kWh energy rate further exacerbates this concern and over-compensates energy efficiency and distributed generation for the costs avoided by their actions. (*Id.*)

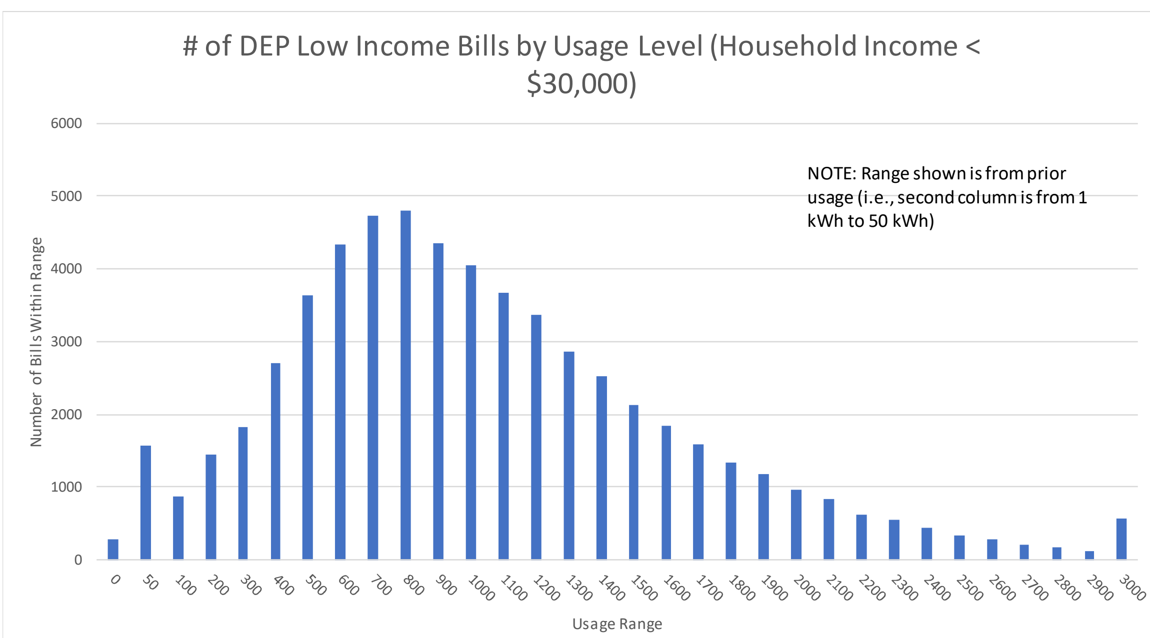
Witness Wheeler explained that while witness Seaman-Huynh's recommendation moves to reduce cross-subsidization, failing to adopt the Company's proposed BFC merely shifts the need to increase the BFC to a future rate case proceeding. (*Id.*)

In response to the allegations that other states have lower BFCs, witness Wheeler observed that the Company's rates should be set based upon its cost of service and an allocation of those costs to the jurisdictions and customer classes based upon methodologies found appropriate by this Commission. (*Id.*) Other utilities' cost and rates are not relevant to a determination of DE Progress' rates.

The Company agreed that increasing the BFC may discourage behind-the-meter customer generation and some energy efficiency initiatives. (*Id.* at 711-5.) However, witness Wheeler argued that underpricing the BFC encourages economically imprudent investment by over-incenting the installation of distributed generation and energy efficiency. (*Id.*) Witness Wheeler testified that the purpose of rate design is to fairly recover the Company's costs from its customers based upon principles of cost causation, not to either encourage or discourage energy efficiency and distributed generation simply for their own sake. (*Id.*) He said the proposed increase to the BFC eliminates a false savings that exists when customers make imprudent investments based on inaccurate price signals. (*Id.*) Providing an inappropriate price signal causes the customer to make the wrong purchase decision and eventually harms the customer when pricing is corrected in a future rate design. (*Id.*)

Regarding witnesses Barnes, Howat and Wallach's proposal to limit the increase in the BFC to less than the customer-related cost, witness Wheeler explained that this approach does not follow the principles of cost causation. (*Id.*) He emphasized that recovering fixed costs such as the costs of poles, wires, transformers and conduit via a kWh charge has the following detrimental consequences: 1) high-usage customers subsidize low-usage customers; 2) low-use customers do not pay the full cost of the utility plant installed to serve them; 3) it does not provide an accurate price signal regarding the Company's costs upon which customers can make economic decisions to make investments that reduce kWh consumption; and 4) it will forever delay appropriate recovery of the Company's customer related costs through the BFC. (*Id.* at 711-5 – 711-6.)

Regarding the impact of the proposed BFC on low-income customers, witness Wheeler testified that DE Progress has many low-income customers with average or above average usage. (*Id.* at 711-6.) Witness Wheeler offered a chart set forth below, to support his position. (*Id.* at 711-7.) The chart illustrates the number of South Carolina DE Progress customer bills by usage levels for customers with household income below $30,000. (*Id.* at 711-6.) The chart demonstrates that lower income customers' electricity usage is quite diverse with many customers having usage above the South Carolina residential monthly average of 1,214 kWh. (*Id.*) In addition, a significant number of low-income customers are clustered around the 600-1100 monthly average kwh. (*Id.*)



Witness Wheeler also noted that since the total number of low-usage customers greatly exceeds the number of low-income customers, there are reasons other than income for low usage such as customers with second homes, vacant homes that are for sale, and customers with solar panels. (*Id.* at 711-7.)

Witness Wheeler explained that while the Company is mindful of the impact of any rate increase on its customers, particularly low-income customers, the Company does not design rates based upon customer incomes, but rather applies cost causation principles to the extent practical. (*Id.*)

He noted that there are other means of addressing the financial needs of low-income customers which are more effective than biasing the rate design, such as Company, state and local programs. (*Id.*) For example, energy efficiency programs, such as the Company's Residential Income Qualified Energy Efficiency and Weatherization Assistance Program, aid low-income customers in reducing their consumption of energy at no cost to the consumer. (*Id.*) Other Company programs, such as the Equal Payment Plan, EPP WeatherProtect Pilot, and payment arrangements, are available to assist all customers in managing their cost for electricity. (*Id.* at 711-8.) The Energy Neighborhood Fund is promoted by the Company and raises funds for local aid agencies to assist low-income customers. Witness Wheeler said that these initiatives are more effective in directly meeting the needs of low-income customers than biasing the rate design. (*Id.*) Finally, he argued that pricing the BFC below cost over-addresses the alleged problem, because all low-usage customers benefit, not just low-income customers. (*Id.*)

In response to allegations that the costs identified by the minimum system methodology are not customer class costs and should not be recovered via the BFC, witness Wheeler rebutted these allegations by explaining that the costs in controversy are fixed distribution facilities costs consisting of poles, wires, transformers and conduit. (*Id.* at 711-9.) Witness Wheeler noted that witnesses Barnes and Wallach agreed in their direct testimony that the distribution facilities costs in question represent poles, conductors, conduit, and transformers. (*Id.*) He observed that these costs are fixed in nature similar to the metering, service drop and billing costs that witnesses Barnes and Wallach support being recovered through the BFC, and that they do not vary with customer consumption. (*Id.*) Witness Wheeler further emphasized that these costs are unlike variable O&M costs and fuel costs which vary directly with energy consumption which are properly recovered via the volumetric kWh rate. (*Id.*) He concluded that recovering these fixed distribution costs via a kWh charge provides an incorrect pricing signal. (*Id.*)

The Commission notes that on cross examination at the hearing in Docket No. 2018-319-E witness Barnes agreed that these distribution facilities are long-lived assets, with lives measured in decades. He further acknowledged during questioning by Commissioner Williams that recovering these fixed costs through a kWh charge can result in the Company not recovering all of its fixed costs if sales decrease due to energy efficiency or behind-the-meter customer generation. (Docket No. 2018-319-E, Tr. Vol. 7, p. 1421-1423, 1434 -1445.)

The ORS and other intervenors recommended the Company employ the principle of gradualism in raising the BFC arguing that the increase should be phased-in over several rate cases. Witnesses Wheeler and Ghartey-Tagoe explained that the Company understands these concerns and believes there is merit in their position. (*Id.* at 711-10.) In witness Wheeler's rebuttal testimony, he suggests that if the Commission determines that it is appropriate to slowly phase-in addressing this issue, the Commission should increase the BFC by an amount equal to 50% of the difference between the current rate and the cost basis. (*Id.*) He said this approach was recently proposed before the NCUC.[70] Adopting this approach would reduce the proposed BFC to $19.03. (*Id.*)

By letter dated March 26, 2019 the Company notified the Commission and the parties that it will agree to the BFCs recommended by ORS witness Seaman Huynh in his surrebuttal testimony for residential customers, SGS customers and SGS Constant Load customers of $11.78, $12.34 and $11.31 respectively.

By letter dated April 10, 2019, the ORS notified the Commission that it supports a request from the agricultural community to limit the increase in the BFC applicable under Schedule MGS to an increase of 24.5%. Based upon the ORS' recommended adjustments, this results in a $21.38 BFC for the MGS rate class. Under examination, witness Wheeler recommended approval of the Company's requested BFC to avoid subsidization explaining that the BFC is approximately 1% of the MGS customer's bill; therefore, the Company request to increase it from $17.17 to $40.03 wouldn't have a significant impact on the customer's bill on a percentage basis. (*Id.* at 743-44.) Much of the increase will also be offset by lower demand and energy rates if more of the revenue requirement is being recovered in the BFC. Accordingly, the average residential monthly bill under the Company's proposal in this case is approximately $142. (Tr. Vol. 3, p. 262.) Thus, the Company's revised position to have a BFC of $11.78 for residential customers still leaves a significant portion of the monthly bill related to usage whereby residential customers can continue to earn energy-efficiency savings and renewable savings. (*Id.*)

The Commission finds that based upon the comprehensive testimony presented by the parties on the issue of the appropriate amount to increase the BFCs, that with regard to all BFCs

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[70] North Carolina Utilities Commission Docket No. E-2, Sub 1142. Wheeler Direct Exhibit No.1.

proposed by the Company other than the BFCs for the residential, SGS Constant Load and SGS customers, the Company's proposed BFCs for those rate schedules are approved. With regard to the BFCs for the residential, SGS Constant Load and SGS rate schedules, the Commission approves the BFCs cited by the ORS in surrebuttal testimony and agreed to by the Company in its March 26, 2019 letter. The $2.85 higher BFC for the residential time-of-use schedule R-TOUD is also appropriate to recover the higher meter cost incurred under this schedule. The Commission finds that the minimum system approach for overall class allocation has merit and integrity for the reasons explained in the testimony of Company witness Hager and that all customers cause the Company to incur the costs of not just a meter, billing services and service drop but also a portion of the distribution system. All customers should pay for their fair share of the costs they cause the Company to incur.

However, the Commission agrees with the ORS and the intervenors that the Commission should be mindful of the impact to customers and a concept of gradualism is appropriate to consider in ratemaking. The Company's acceptance of the BFCs numeric amounts set forth in the Company's March 26, 2019 letter regarding the BFCs in the Company's residential, SGS Constant Load and SGS rate schedules appropriately reflect gradualism, and as such, adequately address the concerns about the Company's original proposal. A gradual approach is not necessary or appropriate under the MGS rate class schedules since the BFC recovers a small portion of the monthly bill. Further, we find that the given the amount of the average monthly customer bill, even with the increase in the BFCs approved in this case, there is still a wide berth for customers to continue to earn energy-efficiency savings and renewable savings.

Low Income Energy Efficiency Programs

Witness Howat proposed changes to the Company's energy efficiency programs targeting low-income customers and that the Commission consider energy efficiency programs that have not been approved**.** (Tr. Vol. 3, p. 279-5 – 279-6.) Company witness Wheeler opposed witness Howat's proposals. He explained that revenues associated with energy efficiency programs are intentionally excluded from rate case revenues because they are considered annually in a DSM/EE cost recovery proceeding. Therefore, any changes to such programs should be considered in those proceedings. (Tr. Vol. 4, p. 711-11.) Witness Wheeler further testified that rate design involves allocating a utility's actual generation, transmission, distribution and customer costs determined by a cost of service study to the utility's customer classes and developing rates to recover those costs. (*Id.* at 711-12.) Witness Wheeler asserted that the issue of whether DE Progress should propose additional energy efficiency programs as proposed by witness Howat should, again, be addressed in DE Progress' DSM/EE proceedings. (*Id.*)

The Commission agrees with the Company. By statute, DSM and EE revenues and programs are annually addressed in a separate proceeding. Those proceedings are the appropriate forum to address the issues raised by witness Howat.

Rate Design Changes

While ORS witness Seaman-Huynh concurred with the majority of rate design changes recommended by the Company, he recommended several changes to the Company's proposed rate designs. (Tr. Vol. 6, p. 1101-6.) The first three changes involved the Company's proposal to revise its time-of-use and other rate designs to reduce the emphasis on summer pricing, to better reflect current marginal cost relationships and to better reflect cost causation. (Tr. Vol. 4, p. 711-12.) Witness Seaman-Huynh recommended these changes be deferred until the Company files its innovative rate structures that are enabled with the deployment of the Smart Meter and Customer Connect billing system infrastructures. (Tr. Vol. 6, p. 1099-11, 1099-13, 1101-6-7.)

Company witness Wheeler disagreed with witness Seaman-Huynh arguing that while the Company understands the ORS' position, attempts to maintain current designs and minimizes disproportionate bill impacts for customers served under each schedule, the Company's changes are not dependent upon alignment with a future rate design, but are intended to reflect current non-disputed cost trends. (Tr. Vol. 4, p. 711-13.) Continuing with the current rate emphasis encouraging winter load by lowering lower winter rates is contrary to the Company's adoption of a winter planning criteria for resource planning purposes. (*Id.*) Witness Wheeler further asserted that marginal energy cost trends indicate a significant narrowing of the difference in marginal energy cost during on-peak and off-peak periods and that the Company's recommendation reflects these changing trends. (*Id.*)

The Commission agrees with witness Wheeler. The Company's proposal is based upon existing facts that are not disputed regarding its summer and winter loads and the decrease in the Company's on-peak and off-peak energy costs. There is no reason to delay revising the Company's tariffs to recognize these changes.

The fourth change involves Rate Schedule SGS-TOU and Large General Service Time-of-Use Schedule LGS-TOU, the ORS is recommending that the off-peak excess demand charge be increased by the same percentage as other rates under the schedule. (Tr. Vol. 6, p. 1101-6.) Witness Wheeler testified that the off-peak excess demand charge applies to the customer's highest demand registered during off-peak hours to the extent it exceeds the on-peak demand in the billing month. (Tr. Vol. 4, p. 711-14.) It is priced to recover distribution-related costs to ensure that customers pay their fair share of costs for extending lines and circuits to their premises. (*Id.*)

Witness Wheeler explained that the Company's proposed rate is set to match the distribution-related unit cost from the Company's functionalized cost of service study to ensure that all customers pay the full cost of extending distribution facilities to the customer's site. (*Id.* at 711-14 – 711-15.) Witness Wheeler emphasized that it is necessary that the billing rate be set to match the unit cost to avoid subsidization within the rate class. (*Id.* at 711-15.) The off-peak excess demand only applies to the demand that exceeds the demand established during on-peak hours and therefore isn't a significant portion of most customer's bill.

The Commission agrees that the rates should reflect the costs the customer cause the Company to incur and recovered via the rate component that matches the functionalized cost.

Finally, under Schedule LGS-TOU, the ORS is recommending that the on-peak demand charges be increased by the same percentage as the energy rates, rather than only increasing the demand rates by 50% of the energy rate change. (Tr. Vol. 6, p. 1101-6.) Witness Wheeler testified that unlike the Company's proposed rates for other time-of-use schedules, the Company doesn't recommend changes to the summer/non-summer demand rate relationship or on-peak/off-peak price relationships for LGS-TOU customers in order to avoid disproportionate increases on these large customers but does recommend that the demand rates be increased less than other rates. (Tr. Vol. 4, p. 711-15.) He explained that current demand rates substantially exceed marginal capacity costs and therefore fail to provide ideal price signals, overly stating the benefit realized by shedding load at the customer's peak. (*Id.*)

Again, the Commission agrees with witness Wheeler. The ORS' recommendation will result in industrial customers served under LGS-TOU to uneconomically reduce load due to incorrect demand pricing. The Commission supports accurate pricing for all customers in order to incent economically prudent energy consumption.

While ORS witness Seaman-Huynh recommended retention of the current one cent energy price differential for winter usage in excess of 800 kWh, witness Howat recommended eliminating the declining block rate design in Rate Schedule RES. (Tr. Vol. 4, p. 711-15.) Witness Howat asserts that the declining block structure penalizes low use customers and discourages customers from investing in and participating in energy efficiency programs. (*Id.*) Witness Wheeler explained that the Company proposes a half cent reduction in the tiered energy rate structure in Schedule RES for usage in excess of 800 kWh in the non-summer months. (*Id.*) He said the current declining block rate structure was adopted to incent winter electric heating which causes a customer's usage to exceed 800 kWh thus improving the customer's annual load factor which in turn increases the efficiency of the Company's electric system and lowers its cost per kwh generated. (*Id.*at 711-15 – 711-16.) Witness Wheeler testified that the Company's proposal to reduce the differential from one cent to one-half cent per kWh moves in the direction suggested by witness Howat, but attempts to minimize the impact on electric heating customers as this change is implemented. (*Id.*at 711-16.)

The Commission agrees with the Company and witness Wheeler. DE Progress' electric heating customers have relied upon the rate design on the RES schedule in making HVAC decisions and modifying their energy consumption behavior. Gradually modifying the RES schedule to allow customers to adjust to reduction in the differential while DE Progress begins its conversion to a rate design based upon winter peak is reasonable.

The majority of rate design changes proposed by the Company were based upon cost studies and were not opposed and are therefore approved. These changes include: Service and Reconnect charges and monthly carrying charge rate applicable to extra facilities included in the Service Regulations, the three-phase charge, the Facilities Charge included in Schedule SI, the

Customer Notification Charge included in tariffs for non-firm service, and changes to the TotalMeter and non-standard metering rates under the Meter-Related Optional Programs Rider. All other changes reflected in the Company's rate designs not otherwise addressed herein are approved.

Dynamic Price Designs

Vote Solar witness Barnes contended that the Company lacks a clear plan for deploying innovative dynamic pricing rate designs. (*Id.*at 711-16.) Witness Wheeler disputed this assertion. He explained that the Company is actively evaluating potential rate designs that can better incent staggering and shifting of usage but that it must first develop the infrastructure required to provide such designs. (*Id.*)

Witness Wheeler testified that to the extent practical, tariffs should be designed to provide cost-based price signals that incent economically-efficient electric use. (*Id.*) Current designs using a single volumetric charge do not communicate to the customer changes in the Company's cost of service based upon real time circumstances. (*Id.*) He explained that while the introduction of both energy and demand rates is an improvement in reflecting cost causation, it still doesn't adequately discourage usage during system peak times. (*Id.*) TOU designs were introduced over 30 years ago and improve price signals by recognizing cost differentials that occur throughout each day, but they provide the same price signals during days with both mild and extreme weather. (*Id.*) Witness Wheeler said the next generation of rate designs can improve these price signals and reward customers that reduce their loads during the peak periods and thereby reduce the Company's cost of service. (*Id.* at 711-16 – 711-17.) These new designs will more accurately communicate the higher cost incurred to serve load during critical peak periods and offer customer savings if they reduce their usage to help mitigate these costs. (*Id.* at 711-17.)

In order to offer such innovative rate designs witness Wheeler explained that three elements are needed. They are:

(1) Granular meter data that supports pricing that more closely aligns with cost causation – this data will be provided the Company's deployment of smart meters.

(2) A robust billing system that supports billing more sophisticated designs – this service will be provided by the Company's Customer Connect Deployment.

(3) Education and tools to aid customers in understanding tariff price signals and effectively shifting usage. (*Id.*)

Regarding the deployment of and benefits of smart meters, witness Wheeler testified that regular watt-hour meters and meters with pre-defined TOU periods lacked the sophistication necessary to offer rates for the majority of customers that varied on a real-time basis. (*Id.*) In the past, sophisticated metering that identified usage for each interval of the month was only cost effective for large customers and customers served under hourly pricing or curtailable rate options because of the expense of such meters. (*Id.* at 711-17 – 711-18.) Smart meter deployment now allows interval level data to be available for all customers; thereby opening the opportunity to provide better price signals to all customers in Company rate designs. (*Id.* at 711-18.)

Witness Wheeler explained that the Company has not yet developed innovative time-of-use rate schedules because it has not completed its smart meter deployment. (*Id.*) The Company needs a full year of usage history data to properly evaluate a new rate design. (*Id.*) The first stage of the Company's investigation is to utilize data analytics to assess whether the current rate classes are appropriate from a cost causation perspective. (*Id.*) Such analytics will allow the Company to determine whether a single residential rate class continues to be appropriate or if there are distinct differences within the class, from a cost causation perspective, meriting further differentiation.

(*Id.*) Witness Wheeler said that this level of analysis was constrained in the past when interval data was only available for a load research sample of the class population. (*Id.*)

Regarding the billing system capabilities needed to provide interval rates, witness Wheeler testified that the current CIS does not support billing at an interval basis because it lacks the capability for different rates to apply to usage during specific hours which are identified on a real-time basis to reflect changes in the Company's costs. (*Id.*) Witness Wheeler said that Customer Connect, addressed by witness Hunsicker, will offer increased flexibility to bill innovative rate designs and has been used by other utilities to support critical peak pricing designs. (*Id.* at 711-19.) Witness Wheeler also observed that effective customer communications are essential to a successful dynamic rate program and will be thoroughly investigated prior to the Company seeking approval of future dynamic designs. (*Id.*)

Witness Wheeler emphasized that offering new interval rate design tariffs at this time would be premature before the infrastructure to support the design is available. (*Id.* at 711-20.) He said the Company is actively pursuing several dynamic pricing pilots in its North Carolina jurisdiction and will use this experience to develop dynamic pricing tariffs in South Carolina. (*Id.*)

The Commission agrees with the Company and witness Wheeler that developing new interval rate designs must wait until the needed infrastructure is in place and the Company can assess the capabilities of its new smart meters, its Customer Connect billing system, and customer communication strategy. In addition, all three elements must be coordinated and integrated before viable tariffs can and should be offered.

Excess Deferred Income Tax Rider EDIT

Witness Barnes contended that revenues associated with the EDIT rider should not be refunded using an energy rate, but rather on a percent of bill basis. (*Id.* at 711-21.) Witness

Wheeler rebutted this proposal. He explained that the Company prefers a uniform approach to implementing riders. The proposed rider is consistent with all other adjustment clauses which use energy rates. Energy sales are non-controversial and are a better choice. Witness Wheeler testified that most revenues associated with the EDIT Rider are demand-related; however, refunding them through a demand rate is impractical since many of the Company's tariffs do not bill customers on a demand basis. (*Id.*) He said updating and refunding EDIT costs as a percentage of the bill adds unnecessary complication and is inconsistent with all other annual clause adjustments and should therefore be denied. (*Id.*)

The Commission notes that no other party opposes the Company's proposed EDIT rider mechanism. The Commission agrees with the Company and witness Wheeler refunding these monies via a kWh credit is simpler to administer than a percentage of bill methodology and easier for the average customer to understand.

Witness Seaman-Huynh suggested that the Rider EDIT rates be calculated using the rate class billing determinants used to calculate tariff revenues rather than using per books sales as recommended by witness Wheeler. (Tr. Vol. 6, p. 1099-18.) The Company didn't contest this recommendation; therefore, it is approved.

Real Time Pricing Hourly Rates

SCEUC witness O'Donnell recommended that the hourly rate in the Company's rate schedule LGS-RTP be set at the lower of the Company's marginal cost or a wholesale market rate available at the time of the sale. (Tr. Vol. 4, p. 711-22.) Witness Wheeler disagreed with witness O'Donnell's proposal arguing that is inconsistent with how schedule LGS-RTP was designed and intended and is unfair to the Company's other customers. (*Id.* at 711-22 – 711-23.)

He explained that schedule LGS-RTP is a voluntary rate option that offers customers the opportunity to purchase incremental energy differing from a baseline load at rates that closely match the Company's incremental cost of providing the next kWh in the given hour. (*Id.* at 711-21.) Participants are therefore given the opportunity to change their consumption of electricity on a real time basis and benefit from the variable pricing. (*Id.*) Hourly rates are provided to customers on a day-ahead basis and are calculated based upon the Company's marginal cost of the generator that is expected to serve the next kWh of system load based upon all available generating plants. (*Id.* at 711-21 – 711-22.) It reflects the change in the Company's fuel cost that is anticipated if the customer decides to exceed or reduce load from their baseline load. (*Id.* at 711-22.) The determination of the marginal cost is consistent with the methodology used by the Company to price opportunity sales into the wholesale market. (*Id.*) Schedule LGS-RTP is only available to nonresidential customers with a contract demand requirement of 1,000 kW or greater. (*Id.* at 711-21.)

Witness Wheeler explained that schedule LGS-RTP hourly rates are based on DE Progress' system production costs; and are not designed or intended to represent or be a proxy for wholesale market-based pricing. (*Id.* at 711-22.) Witness Wheeler testified that the Company actively participates in the wholesale energy market and all customers benefit in the aggregate from those market purchases, not just a select few. (*Id.* at 711-23.) He said schedule LGS-RTP is not a market product and was never intended to provide some customers with optionality beyond the ability of the Company to provide appropriately priced service. (*Id.*) He further argued that applying hourly rates that are lower than the Company's marginal system production costs would potentially result in other customers subsidizing LGS-RTP customers if the forecasted non-firm purchase wasn't available when needed or if other conditions such as transmission constraints wouldn't allow the purchase to occur. (*Id.*) He concluded that the current methodology best reflects the Company's expected fuel cost and is therefore the appropriate basis under which to set hourly rates. (*Id.*)

The Commission agrees with the Company and witness Wheeler. SCEUC witness O'Donnell's proposal would effectively result in the Company shopping the wholesale market for those customers on schedule LGS-RTP and allowing them to pay the lower of the current wholesale market price or the marginal cost of DE Progress producing the next kWh from its system. As witness Wheeler explained, the Company constantly shops the wholesale market for electricity cheaper than the cost of the Company using its system to generate the next kWh. When such lower priced power is found, the Company buys it rather than using its system to generate the same amount of electricity and all customers enjoy the savings benefit, not just a select few on schedule LGS-RTP.

Thus, the Commission approves the Company's proposed rate schedules, tariffs, and service regulations as set forth in Exhibit B to the Company's Application and Hearing Ex. 27 (Wheeler Exhibit No. 1) as revised by the Company's letter to the Commission dated March 26, 2019 regarding the BFCs in its residential, SGS Constant Load, and SGS rate schedules and finds those rate schedules and service regulations are reasonable and approved.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NO. 47

The evidence in support of the findings of fact are found in the verified Application, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

As discussed above, the Company accepted the BFC charges proposed by ORS witness Michael Seaman-Huynh. In response to the Company giving notice to the Commission that it accepted the ORS proposed BFC charges, on March 29, 2019 the ORS wrote the Commission suggesting that any increase in the volumetric component of customer rates to make up for the decrease in revenues from the BFC reduction might violate the provisions of Article I, Section 22 of the South Carolina Constitution. The ORS theory was that any order allowing the volumetric component of the rates in excess of the volumetric component set out in the application and exhibits would conflict with the notice provided to customers of the DE Progress application. The Commission rejects the suggestion by the ORS that Article I, Section 22 is violated in these circumstances.

Article I, Section 22 of the South Carolina Constitution imposes due process requirements on actions of South Carolina administrative agencies: "[n]o person shall be finally bound by a judicial or quasi-judicial decision of an administrative agency affecting private rights except on due notice and an opportunity to be heard…" The South Carolina Supreme Court has held that this provision guarantees persons the right to notice and an opportunity to be heard by administrative agencies. *Ross v. Medical University of South Carolina*, 328 S.C. 51, 492 S.E.2d 62 (1997).

The leading case on what notice is required to afford due process is *Mullane v. Central Hanover Bank & Trust Co*., 339 U.S. 306 (1950) which approved of notice by publication in certain circumstances. The court in *Mullane* described the notice requirement of the due process clause as follows:

> An elementary and fundamental requirement of due process in any proceeding which is to be accorded finality is notice reasonably calculated, under all the circumstances, to apprise interested parties of the pendency of the action and afford them an opportunity to present their objections.

Mullane, *supra*, p. 314. The South Carolina Supreme Court has held that substantial prejudice must be shown to establish a due process claim. *Tall Tower, Inc. v. South Carolina Procurement Panel*, 294 S.C. 225, 363 S.E.2d 683 (1987).

These authorities show that the notice provided of the DE Progress Application in this proceeding easily meets the due process requirements of S.C. Const., Art. 1, §22. The notice informed customers that the Company was asking for an overall 10.3% rate increase amounting to an additional $59 million in annual revenues. The notice also provided an illustration showing that a residential customer, using 1,000 kWh would see an increase of approximately $17.91 per month. The notice described in detail the proposed increase in the BFC from $9.06 to $29.00.

The effectiveness of the notice required by the Commission in this proceeding is best illustrated by the response it generated from the customers who received it. The Commission's Document Management System ("DMS") shows that 12 parties intervened in this proceeding, including influential advocacy groups like the SC NAACP et al. and the Sierra Club. The DMS also shows that no fewer than 341 people have submitted letters of protest responding to the notice. Further proof that DE Progress customers have had ample notice of the Company's proposal, and an opportunity to be heard on it, was shown by the very well attended night hearings held in Florence and Sumter attended by hundreds of customers, and where the Commission heard directly from such customers, primarily residential customers.

The large response to the notice in this proceeding shows that the notice meets the constitutional due process requirements cited in the ORS letter. It stands in stark contrast to the notice provision considered by the South Carolina Supreme Court in *Porter v. South Carolina Public Service Commission*, 338 S.C. 164, 525 S.E.2d 866 (2000).[71] In that case the court considered a notice given for "rate adjustments" that failed to disclose that the adjustments included increases in certain rates of as much as 104%. The court found the notice lacking:

[71] In the *Porter* case, the court considered whether the notice had complied with the provisions of S.C. Code Ann. §58-9-530, a provision that applies to telephone utilities but not electrical utilities.

> Taken as a whole, this notice is not informative and in fact is somewhat misleading since one could conclude the "proposed rate adjustments" merely refers to the reduction in toll switched access rates.

Porter, *supra*, pp. 169-170. The notice of the DE Progress rate adjustment required by the Commission in this proceeding cannot possibly be criticized for failing to inform customers of the potential increase in rates being proposed by the Company and it is clear that customers received notice "reasonably calculated" to provide them the opportunity to be heard as required by *Mullane* and related cases.

This Commission is aware that the primary concern of many of the customers who responded to their opportunity to be heard, by writing letters of protest or showing up to speak at night hearings, was the Company's proposed increase in the BFC. The Company's letter of March 26, 2019 accepting BFC rates set out in ORS testimony was, in part, a response to the views of customers who exercised their right to be heard. The concern expressed by the ORS letter – that due process notice requirements somehow limit the Commission's ability to respond to customer concerns by adjusting component elements of the DE Progress proposed charges – turns the relevant constitutional jurisprudence on its head and would lead to an absurd result. The *Tall Tower* case held that "substantial prejudice" must be shown to establish a due process claim. Contrary to the concern expressed by the ORS, substantial prejudice in this case would result from a ruling that the Commission could not respond to customer concerns and exercise its ratemaking jurisdiction about the BFC by adjusting other components of their charges.[72]

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[72] The Commission has a constitutional responsibility to set rates in this proceeding that provide DE Progress with an opportunity to earn a fair reasonable rate of return on its property devoted to serving the public. *Southern Bell Tel. & Tel. Co., v. Public Service Commission*, 270 S.C. 590, 244 S.E.2d 278 (1978), citing *Bluefield Water Works v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

EVIDENCE FOR FINDINGS AND CONCLUSIONS NO. 48

The evidence in support of the findings of fact are found in the verified Application, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

SC NAACP et al. witness Howat recommended that the Commission direct the Company to, within six months of the final order in this proceeding, prepare, file with the Commission, and make publicly available monthly, in readily accessible spreadsheet format, the data points listed below by zip code:

General Residential Customers

- Number of Residential Accounts
- Total Usage
- Total Billed
- Total Receipts
- Number of Unpaid Accounts 60-90 Days after issuance of a bill
- Dollar Value of Unpaid Accounts 60-90 Days after issuance of a bill
- Number of Unpaid Accounts 90+ Days after issuance of a bill
- Dollar Value of Unpaid Accounts 90+ Days after issuance of a bill
- Total Number of Unpaid Accounts
- Total Dollar Value of Unpaid Accounts
- Number of Accounts Referred to Collection Agencies
- Number of New Payment Agreements
- Number of New Budget Billing Plans
- Number of Accounts Sent Notice of Disconnection for Non-payment
- Number of Service Disconnections for Non-payment
- Number of Service Restorations after Disconnection for Non-payment
- Average Duration of Service Disconnection for Restored Accounts
- Number of Accounts Written Off as Uncollectible
- Dollar Value of Accounts Written Off as Uncollectible
- Dollar Value of Recovered Bad Debt

Low-Income Customers

- Number of Accounts
- Total Usage
- Total Billed
- Total Receipts
- Total Receipts Paid by LIHEAP

- Total Number of Customers Receiving LIHEAP
- Number of Unpaid Accounts 60-90 Days after issuance of a bill
- Dollar Value of Unpaid Accounts 60-90 Days after issuance of a bill
- Number of Unpaid Accounts 90+ Days after issuance of a bill
- Dollar Value of Unpaid Accounts 90+ Days after issuance of a bill
- Total Number of Unpaid Accounts
- Total Dollar Value of Unpaid Accounts
- Number of Accounts Referred to Collection Agencies
- Number of New Payment Agreements
- Number of New Budget Billing Plans
- Number of Accounts Sent Notice of Disconnection for Non-payment
- Number of Service Disconnections for Non-payment
- Number of Service Restorations after Disconnection for Non-payment
- Average Duration of Service Disconnection for Restored Accounts
- Number of Accounts Written Off as Uncollectible
- Dollar Value of Accounts Written Off as Uncollectible
- Dollar Value of Recovered Bad Debt

(Tr. Vol 3, p. 279-36 – 279-37.) In addition, Mr. Howat recommended that the Company be required to conduct a public technical session with the Company and interested stakeholders during the design phase of the data collection and reporting protocol to ensure that resulting reports are of benefit to all parties. (*Id.* at 279-37.)

Witness Howat explained that utility decision-makers are faced with difficult questions regarding the effectiveness of programs and policies designed to ensure regular payment for utility service. (*Id.* at 279-34.) He suggests that the effectiveness of existing regulatory consumer protections and credit and collection practices can only be assessed through data-driven analysis of trends in customer arrearages, service disconnections and related indicators of the magnitude of utility payment troubles. (*Id.*) Witness Howat stated that implementing a regular data collection and reporting protocol, especially given the advances underway in energy and utility industry technology and economics is particularly relevant and timely to gauge the state of low-income and general residential home energy security in the Company's service territory. (*Id.* at 297-35.)

Witness Howat testified that both NARUC and the National Association of State Utility Consumer Advocates have adopted resolutions calling for the collection and reporting of this information and many states such as Ohio, Illinois, Pennsylvania and Iowa report this critical information regularly. (*Id.*)

Company witness Quick testified that the Company does not agree with Mr. Howat's recommendation to provide the requested data by zip code. First, she explained that the Company already provides a significant level of detail pertaining to non-pay service disconnects pursuant to Docket No. 2006-193-EG which requires all investor-owned utilities ("IOUs") in South Carolina, to file quarterly reports on voluntary and involuntary disconnections of service.[73] (Tr. Vol. 3, p. 478-9.) Witness Quick explained that the quarterly reports include the following data and information: (1) total number of accounts whose services have been voluntarily or involuntarily disconnected; (2) the reason for the disconnection; (3) the average duration of service interruption; and (4) the Company procedures in effect governing delinquent account disconnections. (*Id.*) She explained that the Company believes the data contained in these reports provides the Commission with sufficient information about the Company's disconnection policies, procedures and number of accounts affected and any change in reporting obligations for DE Progress would likely cause a ripple effect across all IOUs in South Carolina who must uniformly report on non-pay service disconnects per Docket No. 2006-193-EG. (*Id.*) Thus, witness Quick testified this proceeding is not the appropriate forum to fully evaluate the impact of witness Howat's recommendations. Moreover, she explained that the Company does not currently track the information requested by witness Howat by zip code in the normal course of its business. (*Id.*) Therefore, the Company

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[73] *Quarterly Reports on Involuntary Termination of Electric and/or Gas Service*, Docket. No. 2006-193-EG (July 2006).

would have to perform a series of ad hoc queries on the Company's system to extract the data without a clear way to verify its accuracy. (*Id.* at 478-9 – 478-10.) She also explained that the Company cannot readily distinguish customers by income or any socio-economic indicators in the normal course of its business because that information is not readily available to the Company. (*Id.* at 478-10.) Witness Howat defined "low-income customers" as a customer identified as a participant receiving assistance from the Low Income Home Energy Assistance Program ("LIHEAP"). (*Id.*) However, witness Quick explained that the South Carolina LIHEAP is not required to provide this information to the Company as a prerequisite for a customer to participate in the program; therefore, the Company does not receive or track data in such a way that it can readily provide the requested data points by LIHEAP account. (*Id.*)

Further, the Company has concerns that having this level of detail readily available to third parties may cause some customers to have privacy concerns with how the data could be used. (*Id.*) Witness Howat asserted that this information is needed to assess: (1) the effectiveness of existing regulatory consumer protections and credit and collection practices; (2) the state of home energy security among DE Progress' residential customers, and to evaluate the effectiveness of programs and policies intended to protect that security; and (3) the effectiveness of the credit and collection policies and practices of the Company. (*Id.* at 478-11.) However, Ms. Quick testified that the Company remains unclear on whether and how the requested data points would be used in such an assessment, or how "effectiveness" would be defined as a metric. (*Id.*) In response to Mr. Howat's reference that Ohio reports these metrics regularly, Ms. Quick testified that Duke Energy Ohio participates in the State of Ohio's Percentage of Income Payment Plan ("PIPP") program that Howat referenced in his testimony and in Ohio the community action agent is responsible for collecting income-level data and handling reporting obligations to the state associated with the program, not the utility. (*Id.* at 478-11 – 478-12.)

Witness Howat responded that Ms. Quick's concerns are misplaced because the Company receives LIHEAP payments on behalf of specific customers and credits those customers' accounts accordingly. (Tr. Vol. 3, p. 281-10.) Witness Howat also does not believe that reporting at the zip code level should raise any privacy concerns for customers and that locational data is important for making decisions where about where to make investments in cost-saving energy efficiency.

Based on the evidence presented, we agree with the Company that this is not the appropriate proceeding to address witness Howat's recommendation. As noted by the Company, all IOUs in South Carolina must uniformly report on non-pay service disconnects per Docket No. 2006-193-EG. We do not believe it is appropriate to unilaterally require DE Progress to provide a different level of detailed customer and billing data at this time. In addition, as previously discussed, the Company is implementing a new CIS, Customer Connect. Thus, we believe this recommendation is premature and the Commission needs to better understand the type and reasons for tracking and reporting this type of data in a more appropriate proceeding in which to address this recommendation.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NO. 49

The evidence in support of the findings of fact are found in the verified Application, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

The Company requested that the Commission approve revised depreciation rates in Docket 2018-204-E based on the results of its most recent Depreciation Study commissioned as part of a normal periodic review for compliance with Generally Accepted Accounting Principles. (Tr. Vol. 4, p. 634-9.) In Order No. 2018-530, the Commission approved the Company's request to revise depreciation rates but did not revise customer rates and clarified that the ruling did not preclude the Commission or any party from addressing the reasonableness of the revised depreciation rates in this rate case. In Docket No. 2018-205-E, the Company filed a petition requesting an accounting order and permission to defer the increased expense from the Depreciation Study's new rates in a regulatory asset for consideration in this rate proceeding. On August 9, 2018, this Commission issued Order No. 2018-553 approving the Company's accounting order request. *(Id.)* Since the previous approvals did not revise customer rates, the Company now requests Commission approval to revise customer rates based on the revised depreciation rates approved in Docket No. 2018-204-E. *(Id.)*

Company witness Doss introduced Hearing Ex. 21 (Doss Exhibit 2), the Depreciation Study, prepared by Gannett Fleming Valuation Rate Consultants, LLC, and Hearing Ex. 21 (Doss Exhibit 3), which reflects the revised depreciation rates, and supports the depreciation rates shown on Hearing Ex. 14 (Bateman Exhibit 1 at p. 3.) Notable updates in the Depreciation Study include updates to estimates of final plant decommissioning costs for steam, hydraulic, and other production plants, as well as adjustments for updated probable generation plant retirement dates. *(Id.)* This Commission's Order No. 2018-530 also approved the six adjustments to the Depreciation Study as described in Docket 2018-204-E to reflect: (1) use of a 10 percent contingency for future "unknowns" in the estimate of future terminal net salvage costs instead of the 20 percent proposed in the Depreciation Study; (2) use of a 10-year remaining life for the meters that are being retired pursuant to the Company's AMI program instead of the approximate three-year amortization proposed in the Depreciation Study; (3) use of a 70-R2 survivor curve for Account 356 [Overhead Conductors and Devices] instead of the 65-R2.5 survivor curve proposed in the Depreciation Study; (4) use of a negative ten percent future net salvage for Account 366

[Underground Conduit] instead of the negative fifteen percent future net salvage proposed in the Depreciation Study; (5) use of a 17-year life for new AMI meters [Account 370], instead of the 15-year life proposed in the Depreciation Study; and (6) use of a 20-year amortization period for Accounts 391 [Office Furniture and Equipment] and 397 [Communication Equipment], instead of a 15 year [Account 391] and 10 year [Account 397] amortization period proposed in the Depreciation Study. (*Id.* at 634-11 – 634-12.) The Company continues to believe that the depreciation rates approved in Order No. 2018-530 are reasonable for use in this proceeding. *(Id.* at 634-12.) ORS witness Seaman-Huynh confirmed that the Company used the rates from its 2016 Depreciation Study approved by the Commission in Order No. 2018-530 to determine the appropriate cost levels for depreciation expense in its current filing. (Tr. Vol 6, p. 1099-5.) ORS determined that the study results and methodologies were reasonable and consistent with other South Carolina electric utilities' operating in South Carolina and previously approved by the Commission. (*Id.*)

With the exception of Nucor, who withdrew its testimony subject to the Nucor Stipulation, no intervenor contested the testimony of Company witness Doss regarding the Depreciation Study results or the revised depreciation rates, as adjusted, approved in Order No. 2018-530. Accordingly, the Commission finds and concludes that the Company's request to revise customer rates based on the revised depreciation rates and Depreciation Study adjustments as shown on Hearing Ex. 21 (Doss Exhibit 3) is just and reasonable and therefore approved.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NOS. 50-51

The evidence in support of the findings of fact are found in the verified Application, Nucor Stipulation, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

The Tax Act became law on December 22, 2017. Its headline change was to reduce the corporate tax rate from 35 to 21 percent, and the Company has incorporated this reduction into its base rate revenue requirement, as indicated in the testimony of Company witness Bateman. (Tr. Vol. 3, p. 320-28, 320-30.)

The Tax Act also created a regulatory liability resulting from timing differences between when taxes were collected in the past (based upon the pre-Tax Act 35% corporate rate) and when those taxes will actually be paid in the future at the reduced tax rate of 21%. (*See id.* at 553-7.) DE Progress witness Bateman explained that at the end of 2017, the Company had a certain amount of ADITs on its balance sheet. (*Id.* at 320-31.) These are income taxes which the Company has expensed for accounting purposes, but for which the Company will not need to pay the IRS until some point in the future. (*Id.*) Because the Company has use of the cash until it has to pay the IRS, the ADIT is included as a reduction to rate base and is basically used as a source of financing for investments used to benefit customers – poles, lines, generation plant investments, etc. (*Id.*) With the change in the federal tax rate, the amount that the Company must pay to the IRS in the future for these ADIT obligations has been reduced. (*Id.*) At the end of 2017, the Company calculated this reduction and the difference was carved out and stayed on the balance sheet, and in rate base, as EDIT. (*Id.*) Instead of having an obligation to pay this money to the IRS in the future, the Company now has an obligation to pay it to customers. (*Id.*) However, since the money is currently being used to finance investments benefitting customers, as the Company pays the money to customers, it must find other sources of financing for these investments. (*Id.*) Company witness Bateman pointed out that if the money is returned to customers too quickly, it can put pressure on the Company's credit metrics and create rate volatility for customers. (*Id.*)

The Company proposes that these funds be flowed back to customers through an EDIT Rider, which contains the following five categories of benefits for customers:

1. Federal EDIT – Protected
2. Federal EDIT – Unprotected, Property, Plant, and Equipment related
3. Federal EDIT – Unprotected, not Property, Plant, and Equipment related
4. Deferred Revenue
5. North Carolina EDIT

(*Id*. at 320-30.)

Bateman Second Supplemental Exhibit 3 shows the Year 1 calculation of this rider, and then shows for illustrative purposes how the rider would be calculated in future years. (*See* Hearing Ex. 16 (Bateman Second Supplemental Ex. 3, p. 1-2).) For future years, the Company proposed to file the rider amounts, along with the spread to the classes and derivation of the rate, for each subsequent year with the Commission in this docket by March 31, for rider rates effective June 1. (*Id*. at 320-35.)

<u>Federal EDIT</u>

The Company had, as of December 31, 2017, $207.7 million of federal EDIT. (*Id*. at 553-11.) There are three different buckets of federal EDIT. (*Id*.) In one is approximately $165.0 million of what is called "protected EDIT" – that is, EDIT related to the Company's investment in property, plant and equipment, whose flow back treatment is expressly made subject to IRS normalization rules by the Tax Act. (*Id*.) The normalization rules – specifically, Section 13001(d)(3)(B) of the Tax Act – require protected EDIT to be flowed back over the remaining lives of the property giving rise to the deferred tax balance. (*Id*.)

The remaining EDIT, totaling approximately $42.7 million, is "unprotected" under IRS rules, and, therefore, subject to flow back in a timeframe open to discretionary action by the Commission. (*Id*. at 553-11 – 553-12.) But the lion's share of unprotected EDIT, totaling more than $47.8 million still relates to the Company's investment in property, plant, and equipment, and is the second bucket of EDIT. (*See id*. at 553-12.) This portion of unprotected EDIT is not required to be normalized under the Tax Act. (*Id*.) Although both buckets are property-related, the Internal Revenue Code protects one but not the other. (*Id*.) However, the rationale for normalization applies to this portion of EDIT as much as it applies to protected EDIT, and so normalization at some level is appropriate. (*Id*.) The assets represented in this bucket have an average life of approximately 25 years for DE Progress, although the Company's proposal uses a shorter 20-year period over which to accomplish this flowback. (*Id*.) The testimony of Company witness Panizza establishes that this flowback period is appropriate because it is tied directly to the underlying assets that created the deferred tax balances which became EDIT when the Tax Act dropped the corporate tax rate to 21 percent. (*See id*. at 553-13.) Protected and unprotected property related deferred taxes are no different except for the fact that they come from two places in the Internal Revenue Code and the statute protects one and it does not the other. (*Id*.) The flowback of excess deferred taxes over the life of the underlying assets makes sense, as does normalization concept underlying the 20-year flowback proposal. (*Id*.) Normalization, or the gradual return of EDIT over the life of the capital asset being depreciated, balances the customer's and the Company's interests; it protects the Company's cash flow and also protects the customer against rate volatility, because the deferred balance acts as an offset to rate base, and, therefore, a reduction in rates. (*Id*. at 553-13 – 553-14.)

In addition, as further indicated by witness Panizza, matching the flowback period to the timeframe over which flowback would have occurred absent the Tax Act is important in other ways. (*Id.*) Deferred taxes represent an interest-free loan from the government. The Company then used these funds, at no cost to customers, to invest in its business. (*Id.*) By doing so, the Company avoided having to go to the capital markets to raise this portion of the funds that it invested, and customers saved the capital cost of its being able to use the interest-free loan from the government instead of investor-supplied capital. (*Id.*) But having invested in the business, there is not a readily available reserve pool from which the cash needed to flowback EDIT can be drawn. (*Id.*) Flowback over the 20-year period that more closely matches the asset lives, smooths out the cash flow hit that the Company must take as it returns EDIT to customers and lessens the need for the Company to raise those funds from investors and third-parties. (*Id.*)

The third and final bucket is unprotected EDIT that is not related to the Company's investment in property, plant, and equipment. (*Id.* at 553-12.) For DE Progress, this amount is an asset (as opposed to the other EDIT buckets, which are regulatory liabilities) of $5.0 million.

The Commission addressed the appropriate flowback period in its *Order Addressing South Carolina Electric & Gas Nuclear Dockets*, Docket Nos. 2017-207-E, 2017-305-E, and 2017-370-E, PSCSC Order No. 2018-804 (Dec. 21, 2018). There, the Commission agreed with the return of unprotected EDIT over the remaining book life of the property in question, that is, generally matching the flowback period for protected EDIT. The Commission reasoned that opting for a shorter flowback period "would create a significant mismatch between the amortization of the unprotected EDIT and the actual depreciation of the related assets." (*Id.* at 54.) The Commission also noted that using a shorter period would increase rate volatility, while using the longer period "results in uniformity, ease of administration, and sound regulatory economics including providing intergenerational equity and rate stability to current and future customers." (*Id.*)

Deferred Revenue

Company witness Bateman testified that, as directed in Docket 2017-381-A, the Company began deferring effective January 1, 2018, the impact on customer rates of the reduction in the federal corporate income tax rate. (*Id.* at 320-32.) She explained that the Company will continue to defer the impact from January 1, 2019 through the new rates effective date in this case. (*Id.*) Those additional amounts are not known at this time, and will be included in the Year 2 EDIT rider calculation. (*Id.* at 320-32 – 320-33.) The Company has also netted against the projected balance the deferred balances related to the DERP. (*Id.*) Company witness Ghartey-Tagoe explained that, given the benefits from the Tax Act, DE Progress thought it was reasonable to go ahead and eliminate those DERP balances as the State explores additional options for rooftop solar. (*Id.* at 298-15.) Otherwise, it could be 15 years by the time the Company resolves those balances through existing channels. (*Id.*)

North Carolina EDIT

DE Progress witness Bateman indicated that, similar to the EDIT that results from the reduction in the federal corporate income tax rate, there are EDIT balances that resulted from the reduction in the North Carolina state corporate tax rate. (*Id.* at 320-33.) The Company is proposing to return these amounts to customers in Year 1 of the EDIT rider. (*Id.*)

As described by Company witness Bateman, the Company's EDIT Rider proposal both provides immediate benefit from the Tax Act and continues benefitting customers through the return of deferred taxes over time. The Company's proposal further complies with accounting requirements while preserving the Company's credit rating by not creating undue pressure on cash flows.

ORS witness Schellinger testified that the ORS has reviewed the specific components of the Company's proposed EDIT Rider and agrees that the use of a rider to return the benefits to DE Progress customers is reasonable. (Tr. Vol. 6, p. 1051-3.) He noted that the amortization period associated with the five components is reasonable, and the ORS recommends the approval of the amortization periods as suggested by the Company. (*Id.*) He testified further that the ORS has reviewed the specific components of the EDIT Rider and does not recommend any adjustments. (*Id.*)

<u>Nucor Stipulation</u>

On March 29, 2019, Nucor and the Company entered into an agreement resolving certain issues in this proceeding that were raised by Nucor. As part of the Nucor Stipulation, the Parties agreed to modify the EDIT Rider as follows:

> (a) all deferred revenues from January 2018 through May 2019, related to the reduction in the federal tax rate, shall be returned to ratepayers over three years (instead of five years as originally proposed in the Application); and
>
> (b) the amount of DERP deferred balances to be offset under the EDIT Rider shall be reduced to $6 million (instead of $12.66 million as originally proposed in the Application).
>
> As a result of these modifications, this approach will return excess deferred tax-related dollars to ratepayers more quickly and there will be a larger credit to ratepayers under the EDIT Rider in the first three years of the rate increase compared to the EDIT Rider as proposed in the Application, while also offsetting almost half of the DERP deferred

> balances. This proposal is a reasonable compromise on this issue and is unique to the Company due to DE Progress having had base rate increases in recent years.

(Nucor Stipulation, p. 1-2, para. 1.) Hearing Ex. 16 (Bateman Second Supplemental Exhibit 3) updates the Company's proposed EDIT Rider to reflect the terms of the Nucor Stipulation. (Tr. Vol. 3. P. 324-2.) The total impact of the modifications increases the benefits to customers in Year 1 of the EDIT Rider from $9,881,000 to $12,802,000. Witness Bateman testified that the Nucor Stipulation is the result of negotiations between the Parties and lowers the overall initial increase requested by the Company from South Carolina customers, and resolves many of the issues in the case between Nucor and the Company. (*Id.* at 324-3 – 324-4.)

With the exception of the modifications agreed to by the Company in the Nucor Stipulation, no party has objected to the flowback periods embedded in the EDIT Rider proposal, and the Commission approves them, as modified by the Nucor Stipulation, for the reasons outlined above. The Company's proposed EDIT Rider is just and reasonable, and will result in rates that are just and reasonable, and should be implemented. As shown in Hearing Ex. 16 (Bateman Second Supplemental Exhibit 3, the appropriate annual revenue requirement for the EDIT Rider is a decrement of $12,802,000 in Year 1. (*See* Hearing Ex. 16 (Bateman Second Supplemental Ex. 3, p. 1).) The Company shall file the rider amounts, along with the spread to the classes and derivation of the rate, for each subsequent year with the Commission in this docket by March 31, for rider rates effective June 1. The Commission finds that the EDIT Rider, as modified by the Nucor Stipulation is just and reasonable.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NOS. 52-54

The evidence in support of the findings of fact are found in the verified Application, pleadings, testimony and exhibits in this Docket, and the entire record in this proceeding.

Coal Ash – Summary of the Evidence

As the evidence introduced in connection with the Company's proposals for recovery of its environmental compliance spend is voluminous, it is not recounted in total in this Order. Rather, the Commission will provide a summary of the evidence and will refer to pertinent specific evidence in its discussion of this issue.

1. Company Direct Case: Overview and Costs Sought for Recovery

In her direct testimony, Company witness Laura Bateman testified that DE Progress is requesting recovery of ash basin closure compliance costs incurred in the period from July 2016 through September 30, 2018, as of the time of filing, and updated through December 2018. On a South Carolina retail jurisdiction basis, these costs amount to $50.4 million after applying allocation factors, netting with the cost of removal, incorporating the return on the deferred costs through the expected date on new rates in this case, and subtracting $1.5 million from the balance to exclude the South Carolina retail portion of an amount the NCUC disallowed. Witness Bateman stated that the Company is seeking recovery of these costs over a five-year period in order to mitigate the associated customer rate impacts. (Tr. Vol. 3, p. 320-21 – 320-22.) She explained that the Company has isolated costs related to any fines or penalties it was assessed and/or agreed to pay and is not requesting their recovery in this proceeding, nor will it ever seek to recover these costs from customers. She also explained that while the costs to comply with the Coal Combustion Residuals rule ("CCR Rule") and North Carolina's CAMA are largely duplicative, there are a small portion of the costs that the Company has determined are specific to CAMA, unique to North Carolina customers, and appropriate for direct assignment to North Carolina. The Company is likewise not requesting recovery of those costs. (*Id.*) Finally, witness Bateman explained, the

Company is not requesting recovery of $1.5 million that amounts to the South Carolina retail portion of an expense the NCUC disallowed for prudence reasons.

Witness Bateman also testified that the Company expects to continue to invest significant amounts related to coal ash compliance after the December 2018 cut-off in this case. Instead of requesting recovery of an ongoing level of these costs, the Company is requesting that the Commission approve a continuation of the deferral, similar to what was approved in Docket 2016-227-E, for costs not included in this case. Specifically, the Company proposes deferral of CCR compliance spend related to ash basin closure beginning January 1, 2019, the depreciation and return on CCR compliance investments related to continued plant operations placed in service on or after January 1, 2019, and a return on both deferred balances at the overall rate of return approved in this case. (*Id.*)

2. Company Direct Case: Coal Ash Overview

In his direct testimony, Company witness Kerin provided a detailed discussion of DE Progress' coal ash management history and practices and the new obligations imposed on the Company by the CCR Rule, South Carolina regulatory requirements and preferences, and CAMA. He explained that coal waste, including fly ash, bottom ash, boiler slag, and flue gas desulfurization ("FGD") material, are by-products produced from burning coal at coal-fired generation plants, which has allowed the Company to produce reliable and inexpensive electricity for over a century. He stated that environmental regulations related to ash management have evolved significantly over time, affecting how the Company has operated its coal-fired plants in compliance with those obligations. He testified that at each step in the environmental regulatory evolution process, DE Progress was in line with industry standards and that DE Progress reasonably and prudently managed coal combustion residuals and its coal ash basins. He explained that since its last rate case, DE Progress has become subject to both federal and state regulations that require it to take significant action to close its ash basins. (Tr. Vol. 5-1, p. 850-6 – 850-9.)

Witness Kerin provided a detailed history of coal ash regulation, and he testified that since the early 1900s DE Progress has disposed of ash in compliance with then current regulations and industry practices. Witness Kerin stated that, in many cases, ash basins, of which DE Progress has 17 in the Carolinas, were actually created or relied upon to effectuate prior environmental regulations. In the mid-1970s, the enactment of the Clean Air Act and its subsequent amendment in the 1990s required electric utilities to capture more ash through the use of electrostatic precipitators ("ESP") or bag houses and FGD blowdown. (*Id.* at 850-6 – 850-7.) The Clean Water Act of 1972, and the subsequent creation of the National Pollutant Discharge Elimination System ("NPDES") permitting system, made wet ash handling and ash basins the primary lawful and effective way to meet ash needs and environmental requirements from 1974 until 2015. (*Id.*)

Witness Kerin testified that the federal CCR Rule, which the Environmental Protection Agency ("EPA") proposed in June 2010 and published in final form in April 2015, established national minimum criteria for ash landfills and surface impoundments, which result in different impacts at each unit depending on site-specific factors. He stated that the CCR Rule also contains requirements for how and when ash basins must be closed and that it provides for closure either by cap-in-place or removal of the ash. He noted that as stated in the CCR Rule, the EPA considers coal ash to be a non-hazardous solid waste. (*Id.* at 850-16 – 850-17.)

Witness Kerin testified further that in 2014, DE Progress entered into a consent agreement with the South Carolina Department of Health and Environmental Control ("SCDHEC") relating to the closure of ash basins at the Company's Robinson Steam Station in Anderson County, South Carolina ("Robinson Consent Agreement"). The Robinson Consent Agreement requires DE

Progress to excavate ash from the 1960 lay-of-land ash storage area located south of the ash basin and to initiate permitting of an onsite lined CCR landfill to store the excavated ash. He testified that other South Carolina utilities are closing their ash basins in a similar fashion. (*Id.* at 850-17.)

Witness Kerin noted that all of DE Progress' ash basins must be closed under the CCR Rule, South Carolina regulatory oversight, and/or CAMA. He explained that the Company has begun the process of developing and submitting closure plans at its ash basins and that, ultimately, all closure plans, whether submitted pursuant to the CCR Rule or state requirements, must be approved by SCDHEC or the North Carolina Department of Environmental Quality ("NCDEQ"). (*Id.* at 850-18.) He noted that coal-powered electric generation has ceased at five of the eight coal-fired DE Progress generating facilities with ash basins, including the Cape Fear Steam Station ("Cape Fear"), H.F. Lee Steam Station ("H.F. Lee"), Robinson Steam Station ("Robinson"), Sutton Steam Station ("Sutton") and Weatherspoon Steam Station ("Weatherspoon"). (*Id.* at 850-11.)

Witness Kerin testified that the environmental compliance obligations—the CCR Rule, South Carolina regulatory oversight, and CAMA—represent new regulatory requirements that have significantly changed the operation and life cycle of the onsite ash basins and landfills. He noted that there is a great deal of duplication and interaction between federal rule, state law and agency action and that many of the actions Duke Energy will take will serve multiple compliance purposes. He explained that many actions and draft rules applicable to many utilities, not just Duke Energy, were already being developed prior to 2014 and that the Company is now in another wave of evolution in environmental regulation pertaining to ash. He stated that in response to these new requirements addressing ash disposal activities, the Company is adding dry fly ash, bottom ash, and FGD blowdown handling systems to operating coal-fired plants that are not already so equipped. He also stated that the Company is modifying all active and decommissioned plants to divert storm water and low-volume wastewater away from the basins. He testified that, accordingly, the Company is requesting recovery of the compliance costs related to coal ash pond closures incurred starting July 2016 through December 2018. He testified that these incurred compliance costs are reasonable, prudent, and cost-effective given the individual facts and circumstances at each power plant and ash basin site at issue. (*Id* at 786-8 - 786-9.)

In Exhibit 10 to Company witness Kerin's testimony, he presented the ash pond closure costs incurred from July 2016 through September 2018. Witness Kerin explained why these costs were incurred and why the compliance actions which led to those costs were the most reasonable and cost-effective options given the applicable facts and circumstances. (*Id.* at 850-37 – 850-38.)

Company witness Kerin maintained that DE Progress' historical handling of ash was reasonable, prudent, and consistent with industry standards over time, and that this demonstrates that nothing that DE Progress has done historically is causing the Company to incur any unjustified costs today to comply with post-2015 ash regulations. (*Id.* at 850-37.) Witness Kerin explained that, in 1988, the EPA submitted its Report to Congress on Wastes from the Combustion of Coal by Electric Utility Power Plants ("1988 Report"). The 1988 Report is a comprehensive assessment of the electric utility industry's use of coal and management of CCR up to that point in time. The 1988 Report found that 80% of CCR in the industry was being treated and stored in surface impoundments or disposed of in landfills. Of those units, only 40% were lined with either a synthetic, clay, or composite liner. Historically, surface impoundments were the single most widely used treatment and storage method for ash. At the time of the 1988 Report, landfilling of ash was becoming increasingly common. As of 1988, Duke Energy was employing both surface impoundments and landfills, which the 1988 Report noted were the most commonly used types of treatment, storage, and disposal units used by the industry. (*Id.* 850-21.)

Witness Kerin explained further that the EPA provided another snapshot of the industry in the preamble to the CCR Rule, in which the EPA details that in 2012 alone, over 470 coal-fired electric generating facilities burned over 800 million tons of coal, generating approximately 110 million tons of ash in 47 states and Puerto Rico. In 2012, approximately 40% of the ash generated was beneficially used, with the remaining 60% disposed in ash surface impoundments. Of that 60%, approximately 80% was stored in onsite basins and landfills. Witness Kerin also noted that across the United States, ash disposal currently occurs at over 310 active onsite landfills, averaging over 120 acres in size with an average depth of 40 feet, and at over 375 active onsite surface impoundments. Stated differently, according to witness Kerin, the Company is re-using (selling) and storing ash in the same manner and at approximately the same percentages as the coal-fired utility industry's national averages, and Duke Energy's practices have been and continue to be consistent with those of the industry. Similar to the industry, DE Progress has onsite ash landfills that are actively receiving production fly ash, and some bottom ash, at specific coal-fired generating sites, including the Mayo and Roxboro plants in the Carolinas. Also similar to the industry, DE Progress has active ash basins that will receive bottom ash, and some fly ash through the first quarter of 2019 at specific coal-fired generating sites, including the Asheville, Mayo, and Roxboro plants in the Carolinas. Witness Kerin maintained that the ash handling practices for ash basins and ash landfills in the Carolinas are consistent with the applicable regulatory requirements that were in effect during the history of these units. (*Id.* at 850-22.)

Witness Kerin also testified that DE Progress' ash storage and handling practices are consistent with the practices of other Duke Energy affiliates and Duke Energy peer utilities. Duke Energy as it currently exists today has been formed over the years through the mergers of several utilities with independently operated coal-fired generation, including the Cinergy Corporation in

2006 and Progress Energy, Inc. in 2012. Indeed, going further back in time, Progress Energy, Inc. was created in 2000 from the merger of legacy utilities CP&L and Florida Power Corporation. Similarly, Cinergy Corporation was created in 1994 by the merger of legacy utilities Public Service Indiana and Cincinnati Gas & Electric Company. Yet, witness Kerin concluded, the historical and current ash handling and use of ash basins has been and is consistent across all of the legacy companies that make up Duke Energy today. (*Id.* at 850-23.)

3. <u>Company Direct Case: Cost Recovery Overview</u>

Company witness Julius A. Wright testified that recoverable costs, as they relate to electric utility expenditures in South Carolina, are costs that are just and reasonable and used and useful in the provision of safe, reliable electric service to a utility's customers. He stated that S.C. Code Ann. § 58-27-810 embodies this principle, declaring that "rates shall be just and reasonable," and this standard is repeated in S.C. Code. Ann. § 58-27-850. Witness Wright explained that the "used and useful definition, as it relates to rate base in South Carolina, was clarified in a Commission Order that stated "[t]he rate base is comprised of the value of the Company's property used and useful in providing retail electric service to the public . . . ." Order 87-1381 at 15 (Dec. 30, 1987). He stated that because environmental compliance costs are a necessary cost of providing electric service, these types of costs – and a return on those costs if deferred over time – are recoverable in rates. He explained that the Company incurs costs in compliance with environmental laws and regulations, similar to other costs necessary for the generation of electric power, and that these coal ash disposal costs are like nuclear decommissioning costs or coal plant retirement costs which have long been deemed recoverable for utilities across the country, including DE Progress. (Tr. Vol. 5-2, p. 837-4 – 837-6.)

Witness Wright noted that the Commission has many times allowed the recovery of costs related to environmental expenditures. For example, he noted that costs to remediate ammonia, lime, and other reagents are recovered through the fuel adjustment rider. (*Id.* at 837-10.) He stated that, in his experience, these types of costs that the Company has made over time in compliance with historical coal ash and other environmental regulations, including the reasonable costs associated with operating, maintaining, and upgrading environmental equipment, plus a return, have been routinely recovered as a cost of service through general rate cases, whether as capital or ongoing operation and maintenance expense or some combination thereof. He further noted that the recovery of costs related to environmental compliance is consistent with the public policy of South Carolina "to maintain reasonable standards of purity of the air and water resources of the state, consistent with the public health, safety and welfare of its citizens, maximum employment, the industrial development of the State . . . ." S.C. Code Ann. § 48-1-20. (*Id.* at 837-10.)

Witness Wright noted that coal plants in South Carolina and North Carolina associated with coal ash remediation and closure costs have been used and useful in providing low-cost, reliable power to South Carolina customers for more than a century. In particular, as illustrated in his Graph 1, witness Wright noted that since at least 1990, more than 30% of South Carolina's electric generation was provided by coal-fired generation on an annual basis. (*Id.* at 837-7.) While this dependence on coal has diminished in recent years because of new environmental standards, coal-fired generation continues to be an important component of DE Progress' generation in South Carolina. (*Id.*) Witness Wright's Graph 2 similarly shows that coal has provided fuel to produce approximately 50% of the nation's electric energy over the past seven (7) decades. As witness Wright explained, coal was chosen as a fuel source both in South Carolina and nationwide because it was the least costly, reliable option. But for the use of coal fired generation, historical electric prices in this State would have been higher. Moreover, witness Wright noted that DE Progress' coal-fired generation has directly benefitted the State's customers by virtue of the fact that South Carolina's average retail electric rates have historically below the national average. Consequently, witness Wright noted, these types of costs and, if any amount is deferred over time, a return are appropriately recoverable in rates. (*Id.*)

Witness Wright also noted that the Commission addressed recovery of coal ash expenses in Docket No. 2016-227-E when it allowed DE Progress to recover such expenses amortized over fifteen (15) years, plus the Order's approved return. In addition, he noted that South Carolina and North Carolina have shared environmental expenses on several previous occasions and that cost sharing is common where a utility's operations span multiple states and the utility property used to provide one particular state's electric service may be located in another state. (*Id.* at 837-13.) For example, witness Wright explained that costs related to installing scrubbers at the Cliffside and Allen plants have been shared between South Carolina and North Carolina. Likewise, the Company entered into the Robinson Consent Agreement with SCDHEC) and various environmental groups related to disposal of coal ash at the Robinson plant. Witness Wright explained that the costs incurred pursuant to the Robinson Consent Agreement are shared with North Carolina customers. (*Id.*)

Witness Wright next provided a brief history of coal ash disposal standards with which the Company is required to comply. He explained that the EPA began studying coal ash use and disposal in the mid-1980s. (*Id.* at 837-15.) After several studies and some limited regulatory standards, on May 22, 2000, the EPA determined the need to regulate coal combustion wastes under Subtitle D of the Resource Conservation and Recovery Act. In part as a response to an accident at a surface impoundment at Tennessee Valley Authority's ("TVA") Kingston Fossil

Plant in Harriman, Tennessee, the EPA proposed new coal ash disposal regulations for ash. The proposed regulations specifically referenced the TVA incident as a major reason for the proposed rule and discussed several other coal ash incidents that led to the promulgation of the rule. Witness Wright noted that because the EPA's proposed rule's publication date precedes the February 2, 2014 coal ash release incident at the Dan River plant, the Dan River accident was not mentioned in the EPA's proposed rule, nor could it have been, as a reason for establishing the rule. He also noted that, while the EPA's finalized CCR Rule did reference the Dan River accident, it did not indicate that the accident modified the proposed rule. Finally, witness Wright noted that the proposed CCR regulation strongly encouraged states to adopt at least the federal minimum criteria in their solid waste management plans. (*Id.* 837-15 – 837-18.)

Witness Wright further explained that in August 2014, after the EPA's proposed coal ash regulations were published but prior to their finalization, North Carolina adopted CAMA. He concluded that the North Carolina General Assembly and/or the NCDEQ would likely have taken steps to adopt coal ash regulations shortly after the CCR Rule was finalized in 2015. Likewise, witness Wright testified that, in terms of timing, the new North Carolina state CAMA coal ash standards did result from the Dan River spill, but in terms of the substance of the standards adopted there is not necessarily a connection. In his opinion, the Dan River spill helped prompt the North Carolina General Assembly to examine the State's and national coal ash disposal policies and regulations. He noted that while the CCR Rule and CAMA are similar in many respects, DE Progress must ensure that its coal ash disposal methods meet the standards established in both the CCR Rule and CAMA as well as any other state agency requirements. (*Id.* at 837-17 – 837-18.)

Witness Wright explained that the Company must also follow guidance from SCDHEC with respect to disposal of coal ash. Specifically, the South Carolina legislature passed H.B. 4857 in 2016, which requires utilities to dispose of by-products resulting from the production of electricity in Class 3 landfills except under limited circumstances. The Company is also required to comply with the terms of the Robinson Consent Agreement as agreed to by SCDHEC which requires ash excavation of a 1960 lay-of-land ash storage area located south of the Robinson ash basin and compels the Company to initiate permitting of an on-site CCR lined landfill to store the excavated ash. (*Id.* at 837-18 – 837-19, 837-22.)

Witness Wright stated that the Company has historically spent dollars in order to comply with the coal ash disposal regulations in effect at the time. The Company was, and continues to be, obligated to meet the needs of its customers, which obligation to serve requires the disposal of coal ash subject to the disposal standards at the time. The disposal sites for this coal ash, for which costs DE Progress seeks recovery in this case, are therefore "used and useful" in providing electric service. (*Id.* at 837-24.)

Finally, witness Wright noted that expenses of the type incurred to comply with the CCR Rule, CAMA, and the Robinson Consent Agreement have been routinely recovered as a cost of service and included in rate cases, including the reasonable costs associated with operating, maintaining and upgrading environmental equipment. He noted further that the cost recovery for these rate-based environmental costs include a return. (*Id.* at 837-19.)

4. <u>The Positions of Intervenor Parties other than ORS</u>

Of the intervenors other than ORS, only the SCEUC and Sierra Club submitted testimony related to the recoverability of coal ash costs. SCEUC witness O'Donnell opined that DE Progress should only recover costs to comply with the CCR Rule, and not any CAMA-only costs that exceed CCR Rule compliance costs, based on his contention that Duke Energy caused CAMA. (Tr. Vol. 5-2, p. 1004-35 –1004-39.) Witness O'Donnell purported to compare the DE Progress coal ash

ARO to what he termed similar coal ash AROs of utilities across the United States. He concluded that the Company's ARO coal ash costs are among the highest in the nation and contended that the only discernable difference between the Duke utilities and the other utilities in his comparison was CAMA, which he asserted was prompted by the Dan River spill. He stated that DE Progress did not provide a similar financial analysis for this case. (*Id.* at 1004-40 – 1004-44.) He asserted that there is no evidence to suggest that Duke Energy's coal ash situation is significantly different from that of utilities across the country or from that of utilities in neighboring states. Accordingly, witness O'Donnell recommended a 75% disallowance for the Company's coal ash request. (*Id.* at 1004-44.)

Sierra Club witness Dr. Ezra Hausman contended that the Commission should require the Company to conduct a comprehensive retirement analysis and that the recovery of any coal ash compliance costs be conditioned upon the filing of this analysis. (Tr. Vol. 5-1, p. 786-4 – 786-5.)

5. <u>The Position of ORS</u>

ORS contends that costs incurred as a result of jurisdictional laws (i.e. CAMA) should not lead to increased costs to customers outside of that jurisdiction. (Tr. Vol. 6, p. 1115-30.) ORS admitted that it does not believe that DE Progress acted unreasonably or imprudently to comply with CAMA. (Tr. Vol. 6, p. 1137.) ORS witness Wittliff then calculated a total disallowance of $333,480,308, which he contended reflects costs attributable to CAMA. (*Id.* at 1115-34.) Witness Wittliff suggested that CAMA-only costs disallowed in this proceeding could be recovered in a later rate case if DE Progress can show that those costs would have been incurred under the CCR Rule alone. However, witness Wittliff did not indicate when or if those costs would ever be ripe for recovery. (*Id.* at 1115-45 – 1115-46.)

ORS took no issue with how the Company was complying with CAMA, or any federal or state requirement. Mr. Wittliff also did not testify that the Company's closure approaches at each site would have been unreasonable or imprudent in the absence of CAMA. At the hearing, witness Wittliff testified that his sole directive from ORS was to quantify the additional costs resulting from CAMA compared to what the Company costs would have been if the Company was solely required to comply with the CCR Rule. (Tr. Vol. 6, p. 1113.)

Witness Wittliff testified that all of the Company's costs for DE Progress' Mayo and Roxboro plants in North Carolina should be recovered because they were incurred to comply with the federal CCR Rule. Additionally, witness Wittliff recommended that the Company be allowed to recover its costs to excavate and remediate its impoundments at its Robinson plant near Hartsville, South Carolina. He acknowledged that work at Robinson is being conducted under the South Carolina Robinson Consent Agreement. (*Id*. at 1115-31.)

For the Company's remaining sites—Cape Fear, Asheville, H.F. Lee, Weatherspoon, and Sutton—witness Wittliff concluded that CAMA resulted in three categories of expenditures that were not attributable to the CCR Rule: 1) expenditures for plants not covered at all by the CCR Rule; 2) expenditures for closure and/or excavation options not required under the CCR Rule but required under North Carolina law; and 3) expenditures for actions that would not have been required at this time under the CCR Rule but are subject to accelerated schedules under CAMA. (*Id*.).

Witness Wittliff testified that the Cape Fear plant fell into the first category because its inactive basins are not explicitly covered by the CCR Rule. He testified that DE Progress is excavating ash and closing its basins at Cape Fear solely because of CAMA. ORS' total recommended disallowance for Cape Fear is $33,631,199, which accounts for all compliance costs incurred to-date. Witness Wittliff went on to state that should the EPA later decide to regulate the basins at Cape Fear, DE Progress could then seek to recover those costs in rates from South Carolina customers. (*Id*. at 1115-32 – 1115-34.)

Under the second category, ORS recommends a disallowance of $9,207,711 at H.F. Lee for ash beneficiation costs, which witness Wittliff testified would not be required under the federal CCR Rule. Witness Wittliff asserted that DE Progress' beneficiation project at H.F. Lee falls under the "CAMA-only" category, and that the customers of South Carolina should not have to reimburse the Company for expenses related to that requirement. To calculate the disallowance amount, Mr. Wittliff first concluded that engineering and planning costs should be recoverable because those activities are needed to synchronize work between all of the coal ash sites being closed. To arrive at an estimate of engineering and planning costs associated with impoundment closures, he assumed that engineering and planning activities at all eight plants were accomplished at the same time between 2015 and 2017. Witness Wittliff testified that a site visit at H.F. Lee led him to conclude that a significant portion of the 2018 costs were related to beneficiation, not engineering and planning. For that reason, he recommended disallowing the difference between the total 2018 spend through September ($20,599,578) and the average of the previous three (3) years ($11,391,867) for a total disallowance of $9,207,711. (*Id*. at 1115-36 – 1115-37.) Additionally, witness Wittliff stated that Cape Fear fell under the second category of CAMA expenditures because it was pursuing a beneficiation project at the site, which was not required by the CCR Rule. Because Cape Fear already fell under the first category, witness Wittliff recommended that all compliance costs be disallowed. (*Id*. at 1115-32 - 1115-34.)

Regarding the third category, witness Wittliff identified Sutton as a DE Progress site that has been affected by the accelerated closure timeline imposed by CAMA. He testified that under the CCR Rule, the Company would not have been required to commence closure activities at Sutton until October 31, 2020, while closure under CAMA is required to be completed by August 1, 2019. Witness Wittliff testified that DE Progress should be allowed to recover engineering and planning costs that would have been required for compliance with the CCR Rule, and DE Progress should be allowed to seek recovery at some indeterminate time after 2020 for prudently incurred construction and transportation expenditures related to CCR compliance. To calculate the disallowance, witness Wittliff testified that he utilized a weighted average methodology. He calculated the weighted average of engineering and planning costs as a percentage total of project costs for the four (4) plants – Mayo, Robinson, Roxboro, and Weatherspoon – as 14.02% during the period from 2015 through the end of 2018. Applying that percentage to the total project costs, witness Wittliff concluded that recoverable engineering and planning costs are $69,149,328. ORS recommended that the remaining $186,376,226 of the Company's requested costs be disallowed. (*Id*. at 1115-37 – 1115-40.)

With respect to Asheville, witness Wittliff testified that it fell under the second and third categories of CAMA expenditures. (*Id*. at 1115-31.) Witness Wittliff then testified that the timing of compliance actions at Asheville were not impacted by CAMA, but that the extent of the compliance actions required by CAMA increased the closure costs at Asheville.[74] (*Id*. at 1115-40.) He testified that it would be reasonable for the Company to recover its expenses for engineering and planning and for "cap-in-place" disposal of ash at Asheville. (*Id*.) Absent the North Carolina Mountain Energy Act of 2015, which required the installation of a natural gas-fired combined cycle facility at Asheville, he argued that there would have been ample room for on-site

[74] We note that this testimony conflicts with witness Wittliff's assertion that Asheville falls under the third category of CAMA expenditures, which relate to "accelerated schedules" imposed under CAMA. (*Id*. at 1115-31.)

disposal of ash from Asheville's impoundments. (*Id*. at 1115-41.) Witness Wittliff admitted, however, that he did not conduct any independent engineering analysis to determine whether an alternative on-site disposal option would have been feasible. (*Id.* at 1139-1140.) To calculate ORS' disallowance, witness Wittliff used costs for Robinson, DE Progress' South Carolina facility that it is excavating, as a proxy. (*Id*.) He multiplied the estimated total costs per ton, including engineering and planning, for Robinson by the total tons of ash removed through September 30, 2018 at Asheville to calculate ORS' recommended disallowance of $93,713,264. (*Id*.)

Lastly, ORS recommended a disallowance of a portion of the Company's costs at Weatherspoon, which witness Wittliff classified under the second category of CAMA expenditures. (*Id*. at 1115-31.) Witness Wittliff testified that, while there were similarities to the processes being employed at sites using excavation and placement of ash in an on-site impoundment, there are other aspects of this process that were not required under the CCR Rule. (*Id*. at 1115-42.) Specifically, witness Wittliff contended that DE Progress is beneficiating ash at Weatherspoon, which is required under CAMA but not the CCR Rule. (*Id*.) To calculate ORS' recommended disallowance, he attempted to calculate the allowable engineering and planning work and allowable CCR Rule work. Subtracting his determined allowable costs from the Company's total request, he calculated the recommended disallowance for Weatherspoon to be $6,044,240. (*Id*. at 1115-43.)

ORS witness Wittliff spent the majority of his testimony describing the Company's past ash management practices. ORS witness Wittliff testified that coal-fired electricity generation has been utilized for nearly a century at the Company, beginning in approximately 1923 at the Cape Fear Plant. DE Progress, like many utilities, used unlined earthen impoundments to deposit its CCRs. The first of these impoundments was constructed at H.F. Lee in 1950. Mr. Wittliff stated that in the 1970s, the United States Department of Energy directed that research be done on coal ash residuals and that the research revealed that there was a "growing awareness that the discarded wastes from coal combustion are a serious potential source of surface and ground water contamination" and that the wastes "have the potential for causing great environmental damage if not properly handled." Mr. Wittliff claimed that in 1988, the EPA, in its Report to Congress on the topic of "Wastes from the Combustion of Coal by Electric Utility Power Plants," voiced concerns over the "substantial quantities of wastes" produced by electric utility power plants and concurred with the Los Alamos Report that "[t]he primary concern regarding the disposal of wastes from coal-fired power plants is the potential for waste leachate to cause ground-water contamination" from the potentially toxic metals in the ash due to the fact that "[m]ost utility waste management facilities were not designed to provide a high level of protection against leaching." He claimed that, based on his experience, which according to his *curriculum vitae* does not include oversight of ash management in North Carolina or South Carolina, liners were placed in new ponds built since the mid-1980s and were placed in RCRA Subtitle D compliant landfills built since the mid-1990s. Table 4.1 to witness Wittliff's testimony summarizes the Company's disposal methods at each site over time and indicates that the Company's practices were consistent with his experience, as no unlined impoundments or landfills were constructed after 1982 and 1983, respectively. (*Id*. at 1115-1 – 1115-30.)

Witness Wittliff maintained that the Dan River ash release, a Duke Energy Carolinas, LLC plant, was largely responsible for the development of CAMA in its present form, which he said accelerated remediation and closures and narrowed the field of removal and closure options. (*Id*. at 1115-19.) He asserted that North Carolina was not considering any similar legislation prior to the Dan River spill. (*Id*. at 1115-17 - 1115-18.) He claimed that the plea agreements into which the Company has entered evidence harm to the environment caused by DE Progress' criminal negligence, and that those incidents contributed to CAMA's development. (*Id*. at 1115-19.) He claimed that despite increasing concerns about potential water impacts from CCR impoundments, the Company did not vary from its established practice of building, expanding, and continuing to utilize unlined wet surface impoundments. (*Id*. at 1115-28.)

Deferring to the analysis of witness Wittliff, ORS witness Seaman-Huynh likewise recommended that the Commission disallow recovery of coal ash expenses incurred to comply with North Carolina laws and regulations, like CAMA, that impose requirements above and beyond those in effect in South Carolina. (*Id.* at 1099-6.) In total, ORS witnesses recommended a disallowance of $469,894,472 for what they described as CAMA-only compliance costs, allocated to South Carolina on a jurisdictional basis. (*Id.*)

6. <u>The Company's Rebuttal</u>

<u>Kerin</u>

On rebuttal, Company witness Kerin testified that the disallowance recommendations made by ORS witness Wittliff and SCEUC witness O'Donnell were unprincipled and reflect poor policy and that no recommended disallowance by ORS or SCEUC was based on any alleged imprudence by the Company regarding its closure strategy or execution thereof. (Tr. Vol. 5, pp. 852-3 – 852-5.)

Witness Kerin noted that ORS' recommended disallowance of $333,480,308 for Asheville, Cape Fear, H.F. Lee, Sutton, and Weatherspoon is based entirely on the fact that there is a state border running through the Company's service territory and on the fact that DE Progress is complying with a valid North Carolina law (*i.e.*, CAMA) that Mr. Wittliff views as too expensive. He noted that ORS did not claim or attempt to show that CAMA was unreasonable, excessive, or punitive, that it reflects bad environmental policy, that it conflicts with the CCR Rule, or that the Company took any imprudent or unreasonable action to comply with CAMA or the CCR Rule. He concluded that witness Wittliff's discussion of the Company's CCR management history was therefore irrelevant to his recommended disallowances. (*Id*. at 852-6 – 852-7.)

Witness Kerin also discussed how, in addition to being bad policy, Mr. Wittliff's disallowance methodology and recommendations are based on incorrect and unrealistic assumptions. (*Id*. at 852-8.) He testified that the reasonableness and prudence of the Company's costs should be judged in light of actual circumstances and site conditions and that witness Wittliff has failed to abide by his own standard of not considering speculation. (*Id*.)

Witness Kerin testified that ORS' recommended disallowance for Asheville, based on witness Wittliff's conclusion that an alternative closure approach would have been feasible, was not supported by sufficient engineering analysis. Witness Wittliff did not consider site-specific conditions, including: engineering analysis demonstrating the technical and practical feasibility of cap-in-place or an onsite landfill; the precise location and size of an on-site landfill; cost estimates for cap-in-place or an on-site landfill; permitting requirements for cap-in-place or an on-site landfill; or the likelihood of obtaining requisite federal, state and local permitting approval for cap-in-place or an on-site landfill. Had Mr. Wittliff attempted to investigate any of these factors, he would have found that excavation is the proper closure method for the Asheville site, regardless of CAMA, due to site specific conditions. In addition to the factors above, witness Kerin also testified that seismic conditions in the area would have prevented cap-in-place from being a viable permanent closure solution at Asheville. He noted that the Company's closure approach was consistent with its prior excavation at the Asheville site before CAMA was enacted to provide ash for recycled use at construction projects such as the Asheville airport. Because witness Wittliff's testimony was devoid of any necessary engineering analysis, witness Kerin testified that ORS' recommended disallowance for Asheville should be rejected.[75] (*Id*. at 852-9 – 852-11.)

Witness Kerin testified that ORS' recommended disallowance of Cape Fear costs should be rejected because ORS witness Wittliff fails to consider real-world conditions. He testified that witness Wittliff's suggestion that DE Progress could or would have taken a "do nothing" approach to Cape Fear's ash basins, while at the same time closing all of its other ash basins in South Carolina and North Carolina, defies regulatory reality. He noted that Cape Fear's inactive basins are similar to the inactive ash storage areas at DE Progress' W.S. Lee Plant. (*Id*. at 852-11 – 852-13.) ORS took no issue with the Company's decision to close and excavate the inactive ash areas at W.S. Lee simply because they are located in South Carolina. He stated that considering the Company's approach at W.S. Lee, it would be reasonable to assume that the Company would have taken action at Cape Fear, or been required to do so by regulators, even absent CAMA. He concluded that under Mr. Wittliff's logic, South Carolina customers should refund North Carolina customers all money spent for excavating ash from the inactive basins at the W.S. Lee and Robinson sites in South Carolina because they were otherwise exempt from the CCR Rule. (*Id*.)

With regard to H.F. Lee, Company witness Kerin rebutted the characterization by ORS witness Wittliff's testimony of beneficiation as a novel concept unique to CAMA, and clarified that the beneficiation technologies that are planned for Cape Fear and Buck were first deployed

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[75] Witness Kerin testified that witness Wittliff's testimony regarding Asheville was self-contradictory, thus making unclear as to what alternative closure approach he believed could have been undertaken at the site. Mr. Wittliff recommended that the Company be allowed to recover costs for engineering and planning "and for cap-in-place disposal." Yet, at the same time, he argued that there "would have been ample room for on-site disposal of ash impounded at Asheville," a fact that is irrelevant if he contends that the site should have been capped in place. (Tr. Vol. 6., pp. 1115-40 – 1115-41.) Further compounding the confusion created by his testimony, Mr. Wittliff used DE Progress' Robinson site, where ash is to being excavated and placed in an "on-site landfill rather than capped in place," as a comparison site to Asheville, which again contradicts his argument for the Asheville site. (*Id*. at 1115-41.)

and approved in South Carolina at SCANA coal ash facilities. (*Id*. at 852-13 – 852-14.) Witness Kerin also pointed out that the method by which ORS witness Wittliff calculated the disallowance amount, solely based on his observation that it "appeared" that most of the work he saw during a half-day visit looked like beneficiation work and, therefore, recent costs at the site must be for beneficiation, was not a valid method of determining costs. (*Id*.)

Company witness Kerin further explained that CAMA's beneficiation requirement actually results in a net savings for South Carolina. He explained that Duke Energy selected three sites for beneficiation projects based on the quality and quantity of ash present at the site, logistical factors, and proximity to relevant markets where the beneficiated ash can be sold: H.F. Lee (DE Progress), Cape Fear (DE Progress), and Buck (DE Carolinas). He noted that, while estimated beneficiation costs at Buck are approximately $131 million more expensive than closure without beneficiation on a total system basis, beneficiation at Cape Fear and H.F. Lee under CAMA is providing an estimated net savings compared to closure without beneficiation of approximately $703 million on a total system basis. Witness Kerin asserted that ORS overlooked this fatal flaw to its policy argument, which would result in a situation where, if South Carolina customers will not pay the increased costs of CAMA beneficiation at the Buck site, then they fairly cannot enjoy the superior savings afforded by CAMA beneficiation at the H.F. Lee and Cape Fear sites and would owe North Carolina customers a net refund for those costs savings. (*Id*. at 852-13 – 852-14.)

Witness Kerin next explained the flaws of ORS' recommended disallowance for Sutton. He explained that, in contrast to ORS witness Wittliff's incorrect assumptions, while an accelerated closure schedule would theoretically condense expenditures in the short term, an extended closure schedule, as proposed by ORS witness Wittliff, would actually result in higher total project costs due to increased overhead and changing market conditions, like vendor and resource availability. Witness Kerin stated that, while the Company is ahead of most utilities in the region in terms of its progress in achieving ash basin closure, if it delayed its closure and extended the closure schedule as proposed by ORS witness Wittliff in a world absent CAMA, it would be competing with other utilities for limited, experienced vendors and specialized resources. In addition, he noted that ORS ignored the fact of the Company's observance of these real-world price increases taking place. Finally, witness Kerin noted that witness Wittliff's assumption that DE Progress would not have had to begin closure until 2020 – an assumption that forms the basis of his disallowance calculation – is also incorrect, since the CCR Rule would have required the Company to commence closure in July 2016 after the last placement of waste streams in basins at Sutton. (*Id*. at 852-15 – 852-17.)

Regarding ORS' recommended disallowance for Weatherspoon, witness Kerin testified that, once again, witness Wittliff's assumptions were fatally flawed. He explained that, contrary to witness Wittliff's assertion, DE Progress is not beneficiating ash under CAMA at Weatherspoon. Instead, DE Progress is selling raw, unprocessed ash to buyers who can use it to offset some of the costs for closing that site. Witness Kerin noted that reuse and beneficiation under CAMA are entirely distinct concepts. CAMA required the Company to select three sites for the installation of ash beneficiation equipment to process ash into a refined product. Those sites are H.F. Lee, Cape Fear, and Buck (DE Carolinas). Witness Kerin explained that Weatherspoon did not qualify as a beneficiation site under CAMA and the suggestion that the Company's ash disposal efforts at Weatherspoon are required by CAMA is wrong. (*Id*. at 852-17 – 852-20.)

Witness Kerin also noted that witness Wittliff criticized the Company's closure costs at Weatherspoon, but did not provide an alternative closure approach that the Company should have pursued instead. Witness Kerin testified that the closure approach selected was the most cost effective, feasible strategy. The Company initially selected an offsite landfill option for Weatherspoon whereby ash would be excavated and moved to a landfill disposal offsite. The estimated costs for this disposal strategy were contained in the Company's 2016 ARO and totaled approximately $232 million. Subsequently, DE Progress sought bids for reuse options for the ash at Weatherspoon and was able to secure a contract to provide ash to cement kilns in South Carolina for use in the construction industry. That decision has resulted in approximately $23 million in estimated costs savings for DE Progress' customers compared to what they would have otherwise paid. If ORS' position was accepted, witness Kerin testified, South Carolina customers would not receive their fair share of these savings. (*Id.*)

Witness Kerin also took issue with witness Wittliff's disallowance calculation for Weatherspoon. He testified that witness Wittliff estimated that three-fourths of the Weatherspoon costs in 2017 were attributable to "engineering and planning" without providing any basis or conducting any apparent investigation as to what those actual costs are. He stated that witness Wittliff then estimated that half of fourth quarter 2017 and half of the first three quarters of 2018 were attributable to the CCR Rule, again without any basis. Witness Kerin stated that witness Wittliff therefore arrived at a disallowance number that was not connected to any specific activities or costs at the site. Witness Kerin concluded that ORS' disallowance numbers were a product of fiction and had no basis in the actual facts in this matter. (*Id.*)

Witness Kerin also rebutted SCEUC witness O'Donnell's analysis and recommendation of a 75% disallowance of the Company's coal ash costs. Witness Kerin explained that witness O'Donnell relied on multiple analytical flaws that were fatal to his conclusion and made no effort to address those flaws in his conclusions that were soundly rejected in the Company's North Carolina rate case. Specifically, witness Kerin disagreed with witness O'Donnell's conclusion that his national comparison of CCR assets retirement obligation ("ARO") amounts shows that the Company's ARO is overstated by 75%. He stated that witness O'Donnell appears not to have considered 22 factors that must be accounted for in order to seriously attempt this type of analysis. He also stated that witness O'Donnell made no attempt to quantify DE Progress' coal ash AROs resulting from CAMA, as compared to its obligations under the CCR Rule, or to determine the impetus for coal ash AROs for the other utilities to which he compares the Company. Witness Kerin argued that witness O'Donnell cannot credibly testify that the Company's ARO coal ash costs are higher because of CAMA when he cannot attribute any specific ARO coal ash costs to CAMA or attribute ARO coal ash costs for other companies to any particular regulatory obligation. He explained that even if witness O'Donnell had conducted such an analysis, it would not provide an accurate comparison because other utilities are in very different stages of their coal ash management timeline than DE Progress. Witness Kerin also maintained that the SNL data relied upon by witness O'Donnell are rough estimates and that there is substantial uncertainty over the level of actual closure costs for many of those utilities he listed. For example, his analysis did not consider new legislation that will require Dominion Energy to excavate all of its basins located in the Chesapeake Bay Watershed, which will increase the Company's closure costs by an estimated 897% to 1,314%. Witness Kerin, therefore, recommended that the Commission consider the reasonableness of the Company's ARO amount on its own merits, based on the facts of this case, and without regard to witness O'Donnell's proposal. (*Id*. at 852-20 – 852-25.)

Wright

On rebuttal, Company witness Wright testified that, overall, the theories underlying the disallowances of coal ash remediation expenses recommended by ORS witnesses Wittliff, Seaman-Huynh, and Major, SCEUC witness O'Donnell, and Sierra Club witness Hausman are unfounded, do not provide a proper basis on which costs may be disallowed, and should be rejected by the Commission. (*Id.* at 839-3 – 839-4.)

Witness Wright first disagreed with ORS witnesses Wittliff's and Seaman-Huynh's recommendation to disallow coal ash costs incurred by the Company to comply with North Carolina environmental laws and regulations. Witness Wright noted that neither witness Wittliff nor Seaman-Huynh provided any policy justification for their recommendation that the Commission completely disregard costs incurred to comply with another state's laws. He testified that since the coal ash located at all of the Company's coal sites was indisputably produced as a result of providing electric energy to the Company's customers in both North Carolina and South Carolina, costs related to closure of the Company's CCR impoundments should be borne by customers in both states. He noted that South Carolina and North Carolina have historically allowed recovery of costs incurred due to a jurisdiction-specific law, such as differences in property taxes. In particular, witness Wright noted that the Company has returned and is proposing to continue to return $30 million to South Carolina customers in excess deferred income taxes resulting from North Carolina legislation which decreased the income tax rate. Applying ORS' theory to these facts, witness Wright posited, would prevent South Carolina customers from receiving the significant benefits of the North Carolina legislation. Finally, witness Wright noted that, because the Company is required to abide by the environmental laws of both South Carolina and North Carolina, it would be unreasonable to disallow costs the Company has incurred to follow the law. (*Id.* 839-5 – 839-7.)

Witness Wright reiterated his direct testimony that South Carolina and North Carolina have historically shared the Company's environmental compliance costs. Witness Wright also reiterated that this type of cost sharing is common where a utility's operations span multiple states, and the utility property used to provide one particular state's electric service may be located in another state. Additionally, he provided a number of examples of such cost sharing in other states. (*Id.* at 839-8 – 839-9.)

Legislation aside, witness Wright testified that South Carolina stakeholders have demonstrated a strong preference for excavation of coal ash ponds through settlements and negotiations with its electric suppliers which predate the adoption of the federal CCR Rule and CAMA. Moreover, witness Wright noted that witness Wittliff does not contend that CAMA requirements are unreasonable or out of line with what other states are now requiring regarding ash basin closure, and he provided a number of examples of states that have adopted laws or regulations that impose closure requirements that are more stringent than those set forth in the CCR Rule. (*Id.* at 839-9, 839-12 – 839-14.)

Witness Wright also testified that witness Wittliff failed to apply the appropriate regulatory standard in his disallowance recommendation, which is a finding that the costs (1) were not prudently incurred, (2) were unjust or unreasonable, or (3) were for facilities or expenses that are not used and useful in the provision of electric service. Because witness Wittliff did not engage in any of these required analyses, his recommendation should be disregarded. (*Id.* at 839-16 – 839-18.)

Witness Wright next detailed his disagreement with ORS' specific recommended disallowances at the Asheville, Sutton, Weatherspoon, Cape Fear, and H.F. Lee plants. For each, he noted that Mr. Wittliff did not present any evidence that the Company's closure strategy was unreasonable or imprudent. Accordingly, witness Wright argued, those costs are recoverable by the Company. (*Id.* at 839-18 - 839-23.) Witness Wright further noted that the beneficiation projects the Company is undertaking pursuant to CAMA at the H.F. Lee and Cape Fear sites and through its own initiative at Weatherspoon, which is not subject to the beneficiation requirements of CAMA, will flow back a large cost savings to South Carolina customers. If the Commission were to adopt ORS' argument, witness Wright pointed out, the cost savings of these beneficiation projects would go entirely to North Carolina customers and not be realized by South Carolina customers. (*Id.* at 839-22 - 839-23.)

Witness Wright also disagreed with ORS witness Seaman-Huynh's related recommendation that the Commission disallow recovery of additional costs related to North Carolina laws and regulations. While witness Wright acknowledged that there are times when direct allocation of costs between jurisdictions is appropriate, he explained that such an arrangement is the exception, not the rule. He noted that it is undisputed that South Carolina customers benefitted from the low electric rates and reliable service DE Progress has provided for decades, in large part due to its coal-fired electric generation, and concluded that those customers should likewise pay the costs associated with that service, including new environmental compliance costs. (*Id.* at 839-24 – 839-26.) Witness Wright also explained that witness Seaman-Huynh's recommendation would likely cost South Carolina customers money in the long-run, as it could call into question the equities of sharing assets and economies of scale across a multi-state structure. Finally, witness Wright stated his belief that the Commission's acceptance of the proposed disallowance would negatively impact investors' perceptions of this Commission, which would likely increase the Company's cost of capital, resulting in increased rates. (*Id.* at 839-25 – 839-26.)

Next, witness Wright reiterated his earlier testimony to reject SCEUC witness O'Donnell's assertion that DE Progress was responsible for the passage of CAMA and should be responsible for any coal ash costs above that required by the CCR Rule. Witness Wright also stated that the

Commission should reject witness O'Donnell's recommendation that the Company's environmental compliance costs should be disallowed based on a comparison of the alleged national ARO amounts relating to CCRs. He explained that witness O'Donnell's analysis neither considered the fact that most utilities are behind DE Progress from a timing perspective in both planning and addressing coal ash pond closure, nor reflected the most recent coal ash CCR costs being reported by various electric utilities. Witness Wright also disagreed with witness O'Donnell's statement that the EPA's reconsideration of aspects of its CCR Rule "direct[ly] conflict[s]" with witness Wright's statements about this country's ever-tightening environmental standards, stating that although it was possible that the EPA could modify its current rule, there is no way for DE Progress to know if, when, or how such modification might occur. (*Id.* at 839-35 – 839-39.)

Finally, witness Wright disagreed with the recommendation of Sierra Club witness Hausman that the Commission should require the Company to conduct a comprehensive retirement analysis and that recovery of the CCR costs be conditioned on the filing of such analysis. He noted that the expenditures for which the Company seeks recovery are not optional, and thus they should be allowed unless they are demonstrated to be imprudent, unreasonable, or not used and useful, which no witness has contended or provided evidence to support. According to witness Wright, witness Hausman's proposed conditional recovery would elicit a negative reaction from the investment community since ultimate recovery would be uncertain. (*Id.* at 839-39 – 839-41.)

7. <u>The Surrebuttal of ORS and SCEUC</u>

<u>Wittliff</u>

ORS witness Wittliff testified generally on surrebuttal to his opinion that ORS' recommendations were not unfair because the Company could come back at a later date should the

CCR Rule change in the future. (Tr. Vol. 6, pp. 1117-4 - 1117-5.)

Regarding Cape Fear, ORS witness Wittliff contended that it would be reasonable to believe that the Company would have taken a "do nothing" approach at Cape Fear, despite the closure approach the Company was taking at W.S. Lee and Robinson. In response to the Company's rebuttal, he attempted to draw a connection between the Robinson and W.S. Lee consent orders with SCDHEC and the Dan River accident in 2014, but took no issue with the Company's closure approach or costs for W.S. Lee. He then testified that had the Dan River spill not occurred and had the Company not plead guilty to environmental violations at Cape Fear, it would be reasonable to conclude that compliance at Cape Fear would have been limited by the CCR Rule, which currently does not require any action at Cape Fear. (*Id*. at 1117-5 – 1117-6.)

With regard to Sutton, witness Wittliff acknowledged that adherence to a CCR Rule closure timeline at Sutton would not have reduced overall closure costs for the site. For that reason, he did not recommend a disallowance of future compliance costs. He clarified that his testimony established that most of the costs incurred to-date would not have been incurred prior to September 30, 2018. Even though his direct testimony concluded that closure at Sutton would not have begun until 2020, witness Wittliff testified in his surrebuttal testimony that the closure deadline under the CCR Rule would have been 2021. Witness Wittliff did not, however, adjust his recommended disallowance for Sutton based on these new conclusions. (*Id*. at 1117-6 - 1117-7.)

In responding to witness Kerin's rebuttal testimony regarding Asheville, witness Wittliff claimed that he was forced to develop surrogate cost estimates because the Company provided inadequate information in discovery. He noted that he could have recommended a different, less reasonable disallowance by using estimates the Company had developed in 2012. He asserted that the Commission should accept his surrogate estimate because it is more reasonable. (*Id*. at 1117-

7 - 1117-8.)

With respect to H.F. Lee, witness Wittliff next suggested that Company witness Kerin's conclusion that CAMA's beneficiation requirement was a net benefit to South Carolina customers was unsubstantiated, and that witness Kerin did not state whether the net savings were in comparison to CCR requirements or other additional CAMA requirements that might have been imposed on the Cape Fear and H.F. Lee sites in place of beneficiation. (*Id*. at 1117-9.) Even though his recommended disallowance was based on the Company's compliance with CAMA's beneficiation requirement, witness Wittliff conceded that he did not believe that CAMA's beneficiation requirement was unreasonable. (*Id*. at 1117-10.)

Next, witness Wittliff responded to Company witness Kerin's rebuttal testimony regarding ORS' recommended disallowance for Weatherspoon. He asserted that, based on his observations at the site and the activities described by Company personnel, he continued to believe that the work being done at Weatherspoon was part of a beneficiation process. (*Id*.)

Witness Wittliff claimed that CAMA did not provide any added benefit to South Carolina customers beyond what the CCR Rule alone would provide. He testified that CAMA was appropriately focused on protecting the health and safety as well as the environment of North Carolina. He contended that CAMA included protections above and beyond what was required by the CCR Rule and that these protections accrued primarily to the benefit of North Carolina residents with an unquantifiable, but minimal, benefit to South Carolina residents from early mitigation of risks posed by DE Progress plants in North Carolina that are near the South Carolina border. (*Id*. at 1117-10 – 1117-11.)

Seaman-Huynh

ORS witness Seaman-Huynh characterized the ORS position as a recommendation that South Carolina customers be held harmless for the incremental cost differences attributed to North Carolina state laws, rather than what he termed a mischaracterization of that position by witness Wright as a prohibition on sharing of costs between the states. At the hearing, witness Seaman-Huynh struggled to articulate ORS' position and how it fit into the "just and reasonable" framework. (Tr. Vol. 6, p. 1777.) He noted that the Company is not seeking recovery of the costs to comply with the North Carolina Clean Smokestacks Act, North Carolina Renewable Portfolio Standards, and the North Carolina Competitive Energy Solution for NC (HB 589) laws. (*Id.* at 1101-8 – 1101-9.)

O'Donnell

On surrebuttal, SCEUC witness O'Donnell disagreed with witness Kerin's contention that the Commission should not compare the Company's coal ash costs to those of utilities in other states. He claimed that comparison is a necessary tool to determine the accuracy of cost estimates, and he reiterated his previous claims that the comparison he performed in this case demonstrates that DE Carolina's coal ash expenses are grossly out of line with similar expenses of other utilities across the county. (Tr. Vol. 5-2, 1008-3 – 1008-5.)

Discussion

The Company has met its burden—both the prima facie burden of production and the ultimate burden of persuasion—of showing that the coal ash basin closure costs it actually incurred from June 30, 2016 through December 31, 2018 are recoverable and that a return on those costs is warranted.

First, Company witness Kerin demonstrated that the Company's coal ash management historical practices (*i.e.*, pre-CCR Rule and pre-CAMA) have comported with general industry practices and then-applicable regulations. (Tr. Vol. 5, pp. 850-6 – 850-9, 850-21 – 850-22.) Witness Kerin's testimony on this point was not credibly controverted by any intervenor.

Second, witness Kerin's testimony established that the costs were reasonable, prudent, and used and useful. The Commission finds witness Kerin's testimony to be incisive, credible, and entitled to substantial weight in this case.

Third, Company witness Wright's testimony established that the costs for which the Company seeks recovery were expended to comply with environmental regulatory requirements, including the CCR Rule, Robinson Consent Agreement, and/or CAMA. (*Id.* at 837-19.) As witness Wright explained, prudently incurred expenditures undertaken to enable compliance with the environmental regulations are routinely recoverable in rates. (*Id.* at 837-20 – 837-28.)

I. <u>Intervenor and ORS Challenges to Cost Recovery</u>

Several intervenors have mounted challenges to the Company's recovery (with a return) of its already-incurred coal ash basin costs on a number of grounds. First, in a manner that departs from the just and reasonable framework the Commission has historically followed, ORS, through witnesses Wittliff and Seaman-Huynh, advocated that the Commission disallow recovery of all coal ash costs incurred to comply with North Carolina laws and regulations that impose requirements above and beyond those required by the federal CCR Rule. Second, SCEUC, through witness O'Donnell, advocated that 75% of the Company's coal ash closure costs, which he attributed to the purported heightened requirements of CAMA, should be disallowed from the Company's recovery. Last, Sierra Club, through witness Hausman, proposed that recovery of coal ash costs be conditioned upon the Company's completion of a comprehensive retirement analysis for its coal ash impoundments, the results of which would be filed with the Commission.

As discussed further herein, none of these recommendations are appropriate, and the Commission therefore rejects intervenors' and ORS' proposed disallowances.

A. <u>ORS Approach: Disallowance of Incremental Costs Incurred to Comply with North Carolina Environmental Law and Regulations</u>

ORS proposed that DE Progress should not be allowed to recover costs incurred to comply with any North Carolina environmental law or regulation that imposes duties above and beyond the requirements of federal law. Practically, with respect to coal ash, ORS sought to disallow costs incurred to comply with North Carolina's CAMA which, the ORS witnesses claimed, imposes additional, costly requirements on the Company to close its coal ash impoundments – requirements, it argued, that are absent from the CCR Rule. The Commission agrees with the testimony of Company witnesses Wright and Kerin that this proposal cannot withstand scrutiny from either a regulatory standard or policy perspective.

1. <u>ORS Failed to Apply the Appropriate Regulatory Standard</u>

Utilities may recover rates that are just and reasonable and are entitled to a presumption that their expenses are both reasonable and incurred in good faith. S.C. Code. Ann. §58-27-810; *Hamm v. South Carolina Public Service Comm'n*, 422 S.E.2d 110, 309 S.C. 282 (1992) (internal citations omitted). Accordingly, the burden is on any contesting party to produce evidence that overcomes this presumption as well as any evidence the utility has proffered to substantiate its position. *Util. Servs. of South Carolina, Inc. v. South Carolina Off. of Reg. Staff*, 392 S.C. 96, 109-10, 708 S.E.2d 755, 762-63 (2011). When considering a contested expense, this Commission looks to a number of factors, including whether the expense was (1) not prudently incurred,[76] (2) not known and measurable,[77] or (3) incurred as a result of facilities or other expenses that are not used and useful in the provision of electric service.[78] Here, ORS has failed to present any argument or introduce any evidence that addresses any of these three regulatory cost disallowance factors, let alone that rebuts the presumption that the costs the Company incurred to comply with applicable CCR laws and regulations were reasonable and incurred in good faith.

Instead, ORS put forward a theory that certain compliance costs should be disallowed temporarily or in perpetuity based on jurisdictional allocation principles (*i.e.*, jurisdictional laws should not lead to increased costs to ratepayers outside of that jurisdiction). ORS offered no precedent to support its proposal, and the Commission believes that adoption of such a disallowance theory, which would not require any finding of imprudence, would be fundamentally unfair and inconsistent with prevailing law and regulatory practice.

As witness Wright noted, no ORS witness has performed a prudency analysis of the costs DE Progress has incurred to retire its ash basins in compliance with CAMA, the CCR Rule, and other applicable laws and regulations. Nor has any ORS witness contended that such costs are not known and measurable or used and useful. Indeed, ORS does not appear to take issue with a <u>single</u> closure activity that the Company has undertaken to close its ash basins. As ORS witness Wittliff admitted at the hearing, ORS does not believe any of the Company's closure activities were

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[76] This Commission has many times acknowledged that utilities must be allowed "to recover any costs that are 'prudently' incurred in order to earn a 'fair' return on its investment." *See, e.g.,* Pub. Util. Comm'n Study, EPA Contract No. EP-W-07-064, at p. 5 (Mar. 31, 2011).
[77] Because rates must "reflect the *actual* rate base, net operating income, and cost of capital[,]" the South Carolina Supreme Court has found that recoverable costs "must be known and measurable within a degree of reasonable certainty." *Hamm*, 309 S.C. at 291, 422 S.E.2d at 115 (emphasis added).
[78] South Carolina, like other states, has found that recoverable rate base "represents the total investment in, or the fair value of, the used and useful property which it necessarily devotes to rendering the regulated services." *Southern Bell Tel. & Tel. Co. v. Pub. Serv. Comm'n of S.C.*, 270 S.C. 590, 600, 244 S.E.2d 278, 283 (1978).

unreasonable. (Tr. Vol. 6, at p. 1137.) In the absence of any such evidence, ORS has not met its "burden of production . . . to demonstrate a tenable basis for raising the specter of imprudence[,]" *Hamm*, 309 S.C. at 286, 422 S.E.2d at 112, and disallowance would thus be improper.

2. Commission Precedent and Historical Policy Favor Allowing the Company's Requested Recovery of CCR Costs

Even disregarding ORS' failure to assess the Company's coal ash-related costs under the appropriate regulatory standard, the Commission finds a host of precedential and policy reasons to reject a wholesale disallowance of these environmental compliance costs. While CAMA is a North Carolina law that only applies to DE Progress' North Carolina facilities, that finding is not and should not be the end of the inquiry. The Commission is not aware of any precedent or authority allowing or requiring it to disallow reasonable and prudent costs associated with a jurisdictional law or rule without a competent and compelling reason to do so. Whether the law is punitive, unreasonable, or excessive, whether it reflects bad environmental policy, and whether it conflicts with applicable federal law would be, at a minimum, factors and issues that this Commission would need to consider and resolve before disallowing costs on a purely jurisdictional basis as ORS recommends. As Company witness Kerin noted in his rebuttal testimony, consideration of those factors is completely absent from the evidence presented by ORS. On the other hand, the Company offered ample evidence that demonstrates that CAMA's requirements are consistent with the CCR Rule as well as with the regulatory approaches taken by other states, including South Carolina, and that cost sharing between states is appropriate.

a. The EPA Contemplated that States Would Pass Legislation Like CAMA to Implement and Enhance the CCR Rule at the State Level

In ORS' view, the federal CCR Rule, applied in a vacuum without state involvement, should be the baseline by which the Company's compliance costs should be measured. This

Commission finds that ORS' position shows a lack of understanding regarding the interplay between the CCR Rule and state agencies. As explained by Company witness Kerin, the EPA intended the CCR Rule to provide *minimum* federal standards. In this way, the CCR Rule leaves to the states to approve the method of ash basin closure, meaning that the EPA fully expected and "strongly encouraged" states to adopt at least the minimum standards, and explicitly did not preclude states from adopting additional requirements where it was deemed appropriate. In fact, when it was adopted, the EPA commented that it has no formal role in the implementation of the CCR Rule, noting that "EPA does not issue permits, nor can the EPA enforce the requirements of the rule."[79] Those responsibilities were left to the states. For that reason, the EPA viewed states as necessary and equal partners in the oversight and enforcement from the CCR Rule's very inception. ORS' vision of a CCR Rule-only world directly conflicts with the EPA's clear intent.

To recommend that costs associated with North Carolina regulation of coal ash be disallowed when state regulation was strongly encouraged by the CCR Rule is fundamentally unfair. ORS has singled out CAMA for the sole reason that, in its view, CAMA has resulted in incremental costs above-and-beyond what would have been required under the CCR Rule alone. By taking this position, ORS essentially argues that any cost incurred by the Company relating to its facilities that provided electricity to South Carolina customers to achieve more than minimum standards of environmental protection is not recoverable. Again, no party or intervenor has argued that CAMA is an unreasonable or otherwise improper law, and this Commission is aware of no authorizing standard or policy that would justify a disallowance based on increased cost alone.

[79] "Fact Sheet: Final Rule on Coal Combustion Residuals Generated by Electric Utilities," EPA (December 2014), https://www.epa.gov/sites/production/files/2014-12/documents/factsheet_ccrfinal_2.pdf.

b. CAMA's Requirements Are Consistent with the Company's Existing Obligations in South Carolina

While the South Carolina legislature, itself, has not yet addressed the issue of coal ash remediation, as witness Wright noted, South Carolina stakeholders have demonstrated a strong preference for excavation of coal ash ponds, which predates the adoption of both the CCR Rule and CAMA through settlements and negotiations with electric utilities. (Tr. Vol. 5-1, p. 839-9.) For example, the Company entered into an agreement with SCDHEC, which required excavation of all coal ash units at the Robinson plant, including inactive units that were not addressed by the CCR Rule. Likewise, a settlement agreement between the Company and several environmental groups mandated similar excavation activity at that plant. Importantly, as witness Wright noted, excavation of the ash basins at Robinson is not required by the CCR Rule, and it is the most prescriptive closure option that can be imposed under CAMA, which also contemplates less costly alternatives such as cap-in-place. Nevertheless, SCDHEC has approved excavation plans for these basins, and the North Carolina Utilities Commission recently approved the Company's request to recover the shared costs from North Carolina customers that were incurred to comply with the Company's excavation obligations in South Carolina. *See* North Carolina Utilities Commission Order, Docket No. E-2, Sub 1142, pp. 149, 159, 188, 272 (Feb. 23, 2018). The Commission thus finds that it would be inequitable to prohibit shared recovery of the costs incurred to comply with North Carolina law.

c. CAMA's Requirements Are Reasonable and Consistent with the Obligations Imposed by Other States

Moreover, ORS does not contend, nor could it, that the requirements of CAMA are unreasonable or out of line with what other states now require with respect to ash basin closure. Virginia, for example, has recently adopted state-specific ash legislation that imposes requirements that are consistent with the closure methods being executed at Robinson, Sutton, and Asheville. As witness Wright noted, Georgia, Tennessee, Florida, and Alabama have likewise adopted approaches to ash remediation in addition to the requirements of the CCR Rule. (Tr. Vol. 5-1, p. 839-12 – 839-13.)

Instead, ORS' justification for singling out CAMA is that (1) it is "appropriately focused on protecting public health and safety as well as the environment in North Carolina…and these protections accrue only to the benefit of North Carolina residents and not to the benefit of South Carolina residents." (Tr. Vol. 6, p. 1117-11.) In other words, ORS is advocating that the Commission adopt a standard for cost recovery that makes recovery dependent on showing a local benefit. We decline to accept that standard.

d. Cost Sharing of Environmental Expenses is Appropriate Between Jurisdictions and Supported by Precedent

As noted by witness Wright, were the Commission to adopt ORS' proposal, it would mark a departure from the generally accepted principle that costs may be recovered from customers who benefitted from the underlying service and fuel that led to such costs. ORS did not dispute witness Wright's contention that the coal ash located at DE Progress' various coal ash impoundments was produced as a result of providing electric energy by burning coal as a fuel to the Company's customers in *both* South Carolina and North Carolina. (Tr. Vol. 5 at 837-6.) Accordingly, witness Wright posited, and the Commission agrees, the equities weigh in favor of shared responsibility for the costs incurred to close those impoundments between customers in both states. (*Id.*) Historically, the Company's costs of the fuel (*i.e.*, coal) and the costs to operate and generate the electricity from coal have been shared between South Carolina and North Carolina customers. Furthermore, this Commission has historically allowed shared recovery of the Company's environmental compliance costs. As witness Wright noted in his direct and rebuttal testimony, we previously allowed DE Carolinas to recover from South Carolina customers costs associated with installing environmental compliance equipment for the Cliffside and Allen Steam Stations, both of which are located in North Carolina. *See* Docket Nos. 2011-271-E, 2009-226-E. This type of cost sharing is commonly allowed by commissions in other states where a utility's operations span multiple states and the utility property used to provide one particular state's electric service may be located in another state. *See, e.g.*, *Application of Southwestern Electric Power Company for Authority to Change Rates*, SOAH Docket No. 473-17-64, PUC Docket No. 46449 (Sept. 21, 2017); Order on Rehearing (Mar. 19, 2018) (allowing recovery of environmental costs associated with retro-fitting a facility located in Louisiana to be included in Texas-based utility's rate base); *In re Petition for Approval of 2016 Depreciation and Dismantlement Studies*, Approval of Proposed Depreciation Rates and Annual Dismantlement Accruals and Plant Smith Units 1 and 2 Regulatory Asset Amortization, Order No. PSC-17-0178-S-EI, FL PSC Docket No. 160170-EI (May 16, 2017) (allowing Florida utility to recover from Florida customers environmental costs associated with Georgia plant); *In re Environmental Cost Recovery Clause*, Docket No. 090007-EI (Mar. 31, 2009) (allowing Florida utility to recover from Florida customers environmental costs related to closure of ash pond at Mississippi plant).

As noted by witness Wright, were the Commission to adopt ORS' proposal, it would mark a departure from the generally accepted principle that costs may be recovered from customers who benefitted from the underlying service that led to such costs. In other words, when jurisdictions share joint assets and thus enjoy the mutual benefits that come from sharing those assets, the general rule is that cost sharing between such jurisdictions should be allowed.

Here, ORS did not dispute witness Wright's contention that the coal ash located at DE Progress' various coal ash impoundments was produced as a result of providing electric energy to the Company's customers in *both* South Carolina and North Carolina. (Tr. Vol. 5, p. 839-6.) Likewise, there can be no dispute that South Carolinians benefitted from the low electric rates and reliable service that DE Progress has provided for decades, in large part due to its coal-fired electric generation. Because South Carolina customers have benefitted from the Company's coal-fired electric service, they should likewise pay for the costs associated with that service, including environmental compliance costs.

The Commission also agrees with witness Wright that failure to allow cost-sharing of environmental compliance expenses between customers in South Carolina and North Carolina would have far-reaching implications for the future of electricity provision in this State. For example, if this Commission were to approve ORS' proposed sweeping disallowance, such decision could cast doubt upon the continued benefits of sharing assets and economies of scale across a multi-state structure, as North Carolina customers may be unwilling to shoulder the one-sided burden of environmental compliance for plants located in North Carolina while still contributing to the cost of environmental compliance in South Carolina. (*Id.* at 839-22.) Adopting such a policy would likely result in jurisdictional allocation controversies between South Carolina and North Carolina if, as witness Wright posited, the North Carolina Utilities Commission took umbrage with the inequitable load carried by its citizens. (*Id.* at 839-23.) In addition, a decision of this Commission disallowing recovery of costs on the sole basis that they were incurred to comply with another state's environmental compliance regime could negatively impact investor views on this Commission's regulatory policies, causing an increase in the Company's cost of capital and, ultimately, resulting in higher rates for customers.

Finally, ORS' position that South Carolina ratepayers should not bear their share of the incremental increase in costs to comply with CAMA because they do not have a vote in North

Carolina legislation is entirely without merit. This position was discredited through the testimony of ORS witness Seaman-Huynh who admitted that ORS has the power to intervene in the utility proceedings of other states, including the North Carolina Utilities Commission. (Tr. Vol. 6, p. 1178.) Because ORS declined to intervene in the Company's recent request for rate increase before the North Carolina Utilities Commission, Docket No. E-2, Sub 1142, where that Commission considered the precise issue that is now before this Commission—rate sharing among the states for costs incurred to comply with environmental laws and regulation—ORS cannot now take an opposing position that those costs should not be shared among the states.

For all of these reasons, the Commission finds that the equities weigh in favor of shared responsibility for the environmental compliance costs at issue here between customers in both states.

3. ORS Witness Wittliff's Specific Proposed Disallowances Are Not Reliable or Based on Principled Analysis

ORS hired witness Wittliff, a licensed engineer with GDS Associates Inc. whose *curriculum vitae* reflects experience with coal ash management, to provide consulting services related to the coal ash issues raised by this case. The Company, through witness Kerin, provided credible testimony that the Company's closure strategies and activities are reasonable and prudent from engineering, environmental, and cost perspectives. At the hearing, Mr. Wittliff agreed that DE Progress' acted reasonably and prudently to comply with CAMA. (Tr. Vol. 6, pp. 1171-1173.) His *sole* directive was to calculate a number – the incremental cost of compliance with CAMA as compared to the federal CCR Rule.[80] In light of the Company's evidence and the well-established

[80] "We were asked to determine the marginal impact of the North Carolina Coal Ash Management Act of 2014 and any subsequent amendments on CCR remediation and disposal costs." (Tr. Vol. 6, p. 1108.)

cost recovery standards in this State, the Commission finds it fatal to ORS' proposal that Mr. Wittliff was not asked by ORS to render, at a minimum, an opinion regarding any one of the following issues: the Company's bidding process or selection of vendors for coal ash remediation; whether the Company's closure plans meet engineering and environmental protection standards; whether the Company's activities in furtherance of its closure plans have been executed properly; whether the Company has incurred unnecessary costs to accomplish closure activities; or whether less costly alternatives were available. ORS chose to avoid performing any comprehensive prudency or engineering analysis of real-world conditions in favor of proposing an unprecedented policy proposal for disallowance. The Company, therefore, presented unrebutted, compelling testimony that its requested costs were prudently and reasonably incurred to satisfy its regulatory obligations in South Carolina and North Carolina.

ORS recommended specific disallowances for costs incurred at DE Progress' Cape Fear, Asheville, H.F. Lee, Sutton, and Weatherspoon plants. We will discuss each disallowance and the Commission's further reasons for rejecting those disallowances below.

Cape Fear

ORS recommended a disallowance of all costs incurred by the Company to-date related to coal ash remediation at Cape Fear, a total of $33,631,199. ORS' single basis for the disallowance is that Cape Fear is not regulated by the CCR Rule. ORS did not conduct any independent engineering analysis to determine whether any type of closure was warranted absent amendments to the CCR Rule. (Tr. Vol. 6, p. 1142-1143.) As discussed below, we cannot agree with that premise and, therefore, cannot conclude that a disallowance is justified on that basis alone. ORS' position requires a presumption that the Company operates in a vacuum. To the contrary, real-world conditions do not suggest that DE Progress would have taken a "do nothing" approach at Cape Fear absent CAMA.

When the CCR Rule was initially published, it did not regulate the ash basins at Cape Fear. However, ORS witness Wittliff acknowledged that, after the CCR Rule was promulgated, its exclusion of inactive basins was challenged in federal court in 2015. (*Id*. at 1115-32.) As Company witness Kerin explained, in August 2018, the United States Court of Appeals for the District of Columbia Circuit found "the Rule's legacy ponds exemption is unreasoned, arbitrary, and capricious" and vacated and remanded these provisions of the CCR Rule to the EPA. As a result, the EPA must affirmatively undertake regulatory changes to the CCR Rule to implement the court's judgment, including adding new provisions to the rule specifically regulating legacy impoundments.

Regardless of the application of the CCR Rule to Cape Fear, ORS has not shown why DE Progress' Cape Fear costs are not recoverable. No ORS witness presented evidence that CAMA's requirements, as applied to Cape Fear, are unreasonable or that DE Progress' closure activities are unreasonable. Even absent CAMA, Company witness Kerin presented credible evidence that the Company's closure of Cape Fear would have been consistent with its overall ash management strategy. Witness Kerin testified that the Company is closing inactive ash storage areas at its Robinson facility in Darlington County, South Carolina. Those areas, like the basins at Cape Fear, were originally exempted from the CCR Rule. ORS agreed with the Company's closure activities at Robinson, which DE Progress is undertaking pursuant to a consent agreement with SCDHEC and did not recommend a disallowance. ORS now urges the Commission to apply different standards to the Company's ash basins, depending on whether they reside in South Carolina or

North Carolina. ORS' recommended disallowance, based entirely on a double-standard, is facially arbitrary and we must reject it.

Asheville

ORS recommended that the Commission disallow $98,220,932 for Asheville based on its contention that DE Progress could have pursued a cap-in-place closure method absent North Carolina law. Therefore, ORS argued that the Company should only be allowed to recover the costs it would have incurred to cap the basins at Asheville. Based on the record, we cannot conclude that witness Wittliff's proposed alternative closure approach would have been feasible or supported by sound engineering principles, even absent CAMA.

Mr. Wittliff conceded that if cap-in-place closure would not have been acceptable at Asheville under the CCR Rule, then his entire proposed disallowance must fail. (Tr. Vol. 6, p. 1139.) Mr. Wittliff admitted at the hearing that he "did not conduct an…extensive engineering analysis" to determine whether site conditions at Asheville would have allowed for cap-in-place closure to be used" at Asheville. (Tr. Vol. 6, pp. 1139-1140.) He conceded that only basis for his conclusion that cap-in-place would have been feasible at Asheville is his contention that there would have been ample room for on-site storage had the Company not constructed an on-site natural gas plant. (*Id*. at 1140.) Even so, Mr. Wittliff admitted that "having ample room" is not the only factor that should be considered when determining whether cap-in-place is feasible. (*Id*. at 1141.) He agreed that other factors, such as soil conditions, seismic stability, proximity to surface waters, the age and stability of the basins, and the contents of the basins, would also have to be considered. (*Id*. at 1141-1142.) Yet, Mr. Wittliff admitted that he had not even discussed or considered those factors in his testimony. (*Id*. at 1142.)

Company witness Kerin provided persuasive and unrebutted evidence that the Company's closure approach was the only feasible option based on site-specific conditions and the Company's history of ash management at the site. Mr. Kerin testified that seismic conditions in the area would have prevented cap-in-place from being a viable permanent closure solution at Asheville. He noted that the Company's closure approach was consistent with its prior excavation at the Asheville site before CAMA was enacted to provide ash for recycled use at construction projects such as the Asheville airport. Mr. Wittliff could not meet his own standard to establish by credible evidence that cap-in-place would have been feasible and appropriate at Asheville, and for that reason, we must reject ORS' recommended disallowance for Asheville in its entirety.

H.F. Lee

ORS recommended that the Commission disallow $9,207,711 at H.F. Lee for ash beneficiation, which ORS witness Wittliff testified would not be required under the CCR Rule. ORS makes this recommendation despite witness Wittliff's admission that CAMA's beneficiation requirement is not unreasonable. (*Id*. at 1117-10.)

ORS' disallowance was not based on a finding of unreasonableness or imprudence related to a single vendor contract, purchase order, or invoice, but was instead based on witness Wittliff's observation that it "appeared" that most of the work he saw during a half-day visit looked like beneficiation work. ORS' disallowance, therefore, has no relation to any specific cost that the Company is requesting to recover.

Instead of evaluating the Company's discrete activities and costs, ORS witness Wittliff calculated his recommended disallowance for H.F. Lee using a weighted average cost methodology. Witness Wittliff testified previously in North Carolina on behalf of the Attorney General's Office that he "couldn't get comfortable" enough with the weighted average methodology to present it to the North Carolina Utilities Commission as something it could "hang [its] hat on." (Tr. Vol. 6, pp. 1165-1166.) At the hearing, Mr. Wittliff did not dispute that the methodology he presented in this case was the same that he attempted to use in North Carolina. He did, however, attempt to distance himself from his North Carolina testimony by arguing that he had one more year of data in this case. (Tr. Vol. 6, pp. 1210-1211.) We do not see how the passage of time or additional cost data would make Mr. Wittliff's methodology more reliable.

Mr. Wittliff's weighted average percentage is not dependent on the amount of the data that goes into the calculation, it depends solely on when the calculation is made. Mr. Wittliff testified that the primary purpose of the methodology was to estimate the percentage of the Company's costs incurred through the rate period were attributable to engineering and planning activities. (Tr. Vol. 6, p. 1211.) He then calculated the weighted average of engineering and planning compared to total estimated project costs for sites that he deemed CCR Rule-compliant – Mayo, Robinson, Roxboro and Weatherspoon. He then applied that percentage to his CAMA-affected sites. Any costs beyond the allowable percentage representing engineering and planning costs were attributed to CAMA and would serve as the basis for ORS' disallowance, under Mr. Wittliff's methodology. For any point in time since closure work began at DE Progress' sites, though, Mr. Wittliff could have conceivably calculated the amount of engineering and planning costs for those same four sites and compared that number to the total project estimate to determine a weighted average at that time. As time progresses, one would expect that percentage under Mr. Wittliff's methodology to increase as additional engineering and planning work is performed, but additional time does not make the methodology more reliable, since he was never comparing apples to apples. In other words, he never tried to determine the *actual* engineering and planning costs for his CAMA-affected sites, and instead relied on data from other sites that were operating under different schedules and conditions. We can find no reason why Mr. Wittliff would not have been able to calculate a weighted average for engineering and planning costs when he testified for the Attorney General's Office in North Carolina, but he did not. If he believed his weighted average methodology was not reliable enough for the North Carolina Utilities Commission, it is not reliable enough for this Commission.

We also find that the Company provided unrebutted evidence that CAMA's beneficiation requirement actually results in net savings to DE Progress' customers of $703 million on a total system basis. ORS clearly did not consider the implications of these costs saving, which undermine its entire disallowance theory. ORS cannot have it both ways where South Carolina customers do not pay for the alleged increased costs associated with CAMA yet also receive the benefit of the superior savings afforded by CAMA beneficiation at the H.F. Lee and Cape Fear sites. The cost savings associated with CAMA's beneficiation requirement undermine ORS' disallowance theory, and

Sutton

ORS recommended that the Commission disallow $186,376,226 of costs related to Sutton, which is the amount of DE Progress' request that ORS witness Wittliff attributed to CAMA. Specifically, Mr. Wittliff took the position that absent CAMA, the Company's closure costs would have been incurred later in time. We do not believe that delaying cost recovery for known and measurable closure costs at Sutton is in the best interest of South Carolina ratepayers or consistent with regulatory precedent.

ORS argued that Sutton is a DE Progress site that has been affected by the accelerated closure timeline imposed by CAMA. In his direct testimony, witness Wittliff testified that under the CCR Rule the Company would not have been required to commence closure activities until

October 31, 2020, while closure under CAMA is required to be completed by August 1, 2019. ORS contended that DE Progress should only be allowed to recover certain closure costs, while remaining costs could be sought at some unspecified time in the future after 2020.

By his own admission, however, ORS witness Wittliff incorrectly interpreted the CCR Rule, which in turn invalidates his entire disallowance calculation. In his surrebuttal testimony, witness Wittliff testified that closure under the CCR Rule would have to be *completed* by 2021. It would have been impractical and impossible for the Company to meet that deadline if it started closure activities in 2020 as witness Wittliff suggested. Even though ORS' disallowance calculation was entirely based on a 2020 commencement date, witness Wittliff did not adjust his disallowance to reflect the CCR Rule closure deadline he put forth in his surrebuttal testimony. Thus, we do not conclude that witness Wittliff's proposed disallowance at Sutton is supported by sufficient evidence in the record.

Furthermore, even if we were to accept that CAMA had a material effect on the timing of DE Progress' closure activities at Sutton, ORS has not provided any evidence that this accelerated timing has increased overall project costs. Witness Wittliff acknowledged in his surrebuttal testimony that adherence to a CCR Rule closure timeline at Sutton would not have reduced overall closure costs for the site. To the contrary, witness Kerin explained, delaying or extending the closure schedule as proposed by ORS would actually result in higher total project costs due to increased overhead and changing market conditions, like vendor and resource availability. Witness Kerin stated that, while the Company is ahead of most utilities in the region in terms of its progress in achieving ash basin closure, if it delayed its closure and extended the closure schedule as proposed by ORS witness Wittliff in a world absent CAMA, it would be competing with other utilities for limited, experienced vendors and specialized resources. (Tr. Vol. 5, p. 852-

17.) ORS provided no testimony or evidence to rebut witness Kerin's testimony in this regard. If we were to accept ORS' disallowance theory for Sutton, any short-term savings flowing to South Carolina customers would need to be offset in a later rate proceeding by the cost increases stemming from ORS' extended or delayed closure timeline. This approach is not in the best interest of South Carolina customers.

Weatherspoon

ORS recommended a disallowance for Weatherspoon of $6,044,240 for costs it attributed to CAMA's beneficiation requirements. However, unrebutted evidence shows that Weatherspoon is not a CAMA beneficiation site. CAMA required that the Company select three sites to install a beneficiation project capable of processing 300,000 tons of ash for use in cementitious products. *See* N.C. Gen. Stat. § 130A-309.216. Accordingly, the Company selected DE Progress' Cape Fear and H.F. Lee sites and DE Carolinas' Buck site to comply with this provision. Witness Wittliff did not dispute that the Company selected these three sites for beneficiation projects under CAMA; nevertheless, he concluded in his direct testimony that, based on his observations at a site visit, Weatherspoon was an additional CAMA beneficiation site. Mr. Wittliff attempted to clarify his position at the hearing by testifying that he did not use the "beneficiation" terminology for Weatherspoon. Instead, he stated that he understood from speaking to an unspecified plant employee during his visit that certain beneficial were being undertaken at Weatherspoon even though it "wasn't committed under CAMA…" (Tr. Vol. 6, p. 1161-1162.) Notably, however, witness Wittliff acknowledged that the plant employee "may've . . . misspoke[,]" and his live testimony directly conflicts with his direct testimony where he states, "DEP has represented efforts at Weatherspoon as beneficiation, which is not required under the Federal CCR Rules but is part of the North Carolina CAMA provisions." (*Id*. at 1115-42.) ORS' disallowance for Weatherspoon hinges on ORS establishing some connection between the Company's closure activities and CAMA, a connection which Mr. Wittliff rejected at the hearing.

We also cannot square witness Wittliff's conclusion in his direct and surrebuttal testimony that Weatherspoon is a CAMA beneficiation site with the fact that the Company had contracted with two South Carolina companies to provide 230,000 to 280,000 tons of ash for reuse. For Weatherspoon to be a CAMA beneficiation site, it would have to be capable of processing a minimum of 300,000 tons per year, which witness Wittliff's testimony conceded it did not. The undisputed evidence presented to the Commission as discussed above shows that Weatherspoon is not a CAMA beneficiation site. In fact, on cross-examination witness Wittliff admitted that Weatherspoon is not a designated CAMA beneficiation site and that his recommendation for a beneficiation disallowance is based solely his understanding of one or more statements made by an unspecified plant employee—whom witness Wittliff acknowledged may have misspoke—that the Company was performing certain beneficiation-like activities at Weatherspoon. (*Id.* at 1155-1162.) Moreover, Mr. Seaman-Huynh confirmed that, notwithstanding its disallowance recommendation, ORS believes the profits from any beneficial re-use of Weatherspoon ash should be shared with South Carolina ratepayers. (*Id.* at 1156-1157.) ORS cannot have it both ways, and the Commission finds that it would be improper to mandate sharing of profits with South Carolina ratepayers while at the same time prohibiting the Company from recovering the costs incurred to achieve such profits. Because ORS has provided no evidence to support its theory that CAMA imposed costs at Weatherspoon above and beyond the CCR Rule, we reject ORS' recommended disallowance for Weatherspoon.

We also find compelling Company witness Kerin's unrebutted testimony that the closure approach selected was the most cost effective, feasible strategy. The Company's closure approach at Weatherspoon has actually resulted in approximately $23 million in estimated costs savings for DE Progress' customers compared to the costs if the Company had not sought a reuse opportunity for the ash. ORS witness Wittliff did not suggest any other alternative closure approach that would have resulted in more savings to South Carolina customers. Under ORS' flawed position, South Carolina customers would have to refund this State's share of these savings. Because Weatherspoon is not a CAMA beneficiation site and because the Company selected the most cost-effective approach, we reject ORS' recommended disallowance of Weatherspoon costs.

B. <u>SCEUC Approach: Disallowance of Costs Incurred to Comply with CAMA</u>

The approach proposed by SCEUC—that DE Progress should not recover any costs under CAMA that exceed CCR Rule compliance costs—is nearly identical to that of ORS in its impact on the Company's proposed cost recovery, even if SCEUC's rationale for the proposed disallowance differs from that of ORS. According to witness O'Donnell, these CAMA-specific costs should be disallowed because, in witness O'Donnell's opinion, the Company's actions precipitated the passage of CAMA, and its restrictive provisions have caused the Company to incur coal ash expenses far beyond that of utilities in other states. (Tr. Vol. 5-2, p. 1004-38 – 1004-39.) More specifically, in witness O'Donnell's view, CAMA sets a more aggressive coal ash basin closure schedule for certain of the Company's basins than would have been set under the CCR Rule alone, and the more aggressive schedule leads, again in its view, to higher cost. (*Id.*)

Witness O'Donnell proposed a 75% disallowance of the Company's coal ash compliance costs, but he does so predicated on what he terms a "financial analysis" that compares the size of the Company's coal ash ARO with the AROs established by other utilities to capture their coal ash basin closure expense. However, witness O'Donnell's analysis is fatally flawed, as demonstrated by the evidence in this case. In particular, witness O'Donnell's analysis is devoid of any attempt to control for the differences utilities have in determining their closure cost estimates, the differences in the timing of their estimates, or even the physical differences in their coal ash ponds.

Finally, as witness Wright noted, the ARO numbers in witness O'Donnell's analysis do not reflect recent legislation, such as a Virginia law that will significantly increase Dominion Energy's coal ash-related costs, and recent policy decisions of the utilities themselves, such as Georgia Power's decision to excavate an additional 29 million tons of ash at various of its coal ash impoundments. (Tr. Vol. 5-1, p. 839-34 – 839-35.) Witness Wright indicated, and the Commission agrees, that witness O'Donnell's failure to take these factors into consideration renders his "analysis" irrelevant—it tells one nothing about the true apples-to-apples comparison of the utilities' AROs. In any event, witness O'Donnell has failed to identify a specific level of costs that is imprudent, unreasonable, or not used and useful, and instead advocates for a blanket 75% cost reduction. As witness Wright pointed out, this is an inappropriate mechanism for adopting a cost disallowance. (*Id.* at 839-37.) The Commission agrees and rejects SCEUC's argument.

Further, the Commission does not accept witness O'Donnell's opinion that the Company "caused" CAMA, nor does it accept that notion as a proper basis for denying reasonable and prudent costs. Witness O'Donnell presented no evidence of such causation, while witness Wright pointed to the history of the CCR regulation, which strongly encouraged the states to adopt at least the federal minimum criteria in their solid waste management plans, as evidence that the North Carolina General Assembly and/or the NCDEQ would likely have taken steps to adopt coal ash regulations shortly after the CCR Rule was finalized in 2015. (*Id.* at 839-17.) Finally, even if DE Progress or one of its sister companies did "cause CAMA" as these witnesses allege, a premise the

Commission does not accept, any such causation is not a legal basis for disallowing otherwise recoverable costs.

C. Sierra Club Approach: Conditional Recovery

The Sierra Club argued that any recovery of coal ash expenses should be conditioned upon the Company's completion of a comprehensive retirement analysis to be filed with the Commission. (Tr. Vol 5, p. 786-5.) As a threshold matter, the Commission notes that Sierra Club has not offered any evidence to suggest that the Company's coal ash remediation costs are imprudent, unknown or unmeasurable, or not used and useful. Moreover, Sierra Club failed to identify any authority to support its proposed conditional recovery structure, and the Commission is likewise unaware of any such precedent. As witness Wright noted, the conditional recovery proposed by Sierra Club would cast a "shadow of delay" on future requests for recovery that would likely elicit a negative response from the investment community. (Wright Rebuttal 839-38.) Perhaps, most importantly, Sierra Club's proposal is not practical. It would require the Commission to defer recovery of coal ash expenses that are currently being incurred to comply with legal requirements until an uncertain date in the future, but it proposes no mechanism or date certain by which the Commission should approve such expenses. Such delay would violate a fundamental tenet of this State's regulatory policy: that prudently incurred costs to comply with laws and regulations are recoverable within a temporal proximity to the date they were incurred. In the absence of any legal support for its position, the Commission rejects Sierra Club's proposal.

At the hearing, the Commission took judicial notice of Sierra Club's cross examination of Company witness Kerin in the recent DE Carolinas rate case at the request of Sierra Club's counsel. (*Id.* at 855-856.) During cross of witness Kerin in that case, counsel for Sierra Club appeared to argue that the Company's request for recovery of ash basin closure expenses should be disallowed because of certain exceedances of North Carolina's 2L groundwater standards (the "2L Standards"). No intervenor, including Sierra Club, raised this argument at any point throughout the course of the instant case. To the extent Sierra Club intended to raise the issue through judicial notice of its cross-examination of witness Kerin, the Commission finds the argument to be unpersuasive given that neither Sierra Club nor any other intervenor has suggested that the Company's efforts to close its existing ash basins was unreasonable, imprudent, or otherwise impacted by the existence of any 2L Standard exceedance.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NO. 55

The evidence supporting these findings and conclusions is contained in the verified Application, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

In its Application, DE Progress stated that since its last rate case, the Company made significant investments in its generation fleet to reduce its environmental footprint by adding state-of-the art technology and environmental equipment to reduce emissions. (Application at 9.) For example, the Company added two new combustion turbines ("CTs") for the Sutton Combined Cycle generation facility at the Sutton Energy Complex and made capital additions at Roxboro Station to convert to a dry bottom ash system to comply with the CCR Rule, totaling approximately $100 million. (*Id.*) Company witness Turner testified about DE Progress' Fossil/Hydro/Solar generation fleet, including major capital additions since its last rate case as well as operational performance results for the Test Period.

In her direct testimony, witness Turner stated that the Company's Fossil/Hydro/Solar fleet consists of 9,217 MWs of owned generating capacity. (Tr. Vol. 4, p. 568-4.) Included in the total amount are approximately 3,544 MWs of coal-fired generation resources, which represents three generating stations and a total of seven units. (*Id.*) These units are all equipped with emission control equipment, including selective catalytic reduction equipment for removing nitrogen oxide ("NO_x"), FGD equipment for removing sulfur dioxide ("SO_2") and low NO_x burners. (*Id.*) According to witness Turner, this inventory of coal-fired assets with emissions control equipment enhances the Company's ability to maintain current environmental compliance and concurrently utilize coal with increased sulfur content; thereby providing flexibility for DE Progress to procure the most cost-effective options for fuel supply. (*Id.*) She also testified that the Company's Fossil/Hydro/Solar generating units operated efficiently and reliably during the Test Period. (*Id.* at 568-10.) In fact, when comparing the Company's operational performance to the average of comparable units based on capacity rating reported by the North American Electric Reliability Council ("NERC") for the period 2013 through 2017, the Company's results were comparable or better than the NERC 5-year average comparisons. (*Id*. at 11.)

Sierra Club witness Hausman, in his direct and surrebuttal testimony, recommends to the Commission that it deny the Company's request to recover its $100 million investment in the dry bottom ash system at Roxboro because, according to him, the Company did not demonstrate that the investment was economically preferable to the early retirement of the plant. (Tr. Vol. 5-1, p, 786-4.) Additionally, witness Hausman recommends the Commission require the Company to complete comprehensive economic and retirement analyses of each of its coal stations. (*Id.*)

In rebuttal testimony, witness Turner testified that the Company's investment in the dry bottom ash system at Roxboro allows the Company to be in compliance with environmental regulations. (Tr. Vol. 4, p. 570-3 – 570-4.) Without the conversion, Roxboro would be required to shut down and replacement generation would be needed for capacity needs. (*Id.* at 570-4.) Further, while the Company did not perform a formal retirement analysis for Roxboro, the Company did perform a comparable, comprehensive retirement analysis in 2016 for the Mayo station, which showed continued operational benefits outweighed the significant cost of replacement generation and new transmission that would be required to retire the facility. (*Id.* at 570-5.) Also, specific to Roxboro, the Company did consider system operational impacts, timing impacts, and overall feasibility of a potential retirement scenario. The result of the analysis was, given the size of the Roxboro plant, replacement generation would have been costly and difficult to build prior to the compliance deadline established by a combination of environmental regulations. (*Id.* at 570-4.) Specifically, the Company looked at the need for replacement generation of the approximate 2,400 MW Roxboro facility, at a cost of approximately $2 billion, excluding gas pipeline cost. (*Id.*) Further, the station had already made significant investment in SCR and FGD systems that made the station well outfitted for air regulations. (*Id.*)

At the hearing, witness Turner testified that the majority of witness Hausman's positions and conclusions pertain to recommended analyses for capital investments that may or may not occur in the future. (*Id.* at 625.) Accordingly, the Company believes witness Hausman's recommendations are more appropriately addressed in an Integrated Resource Planning ("IRP") proceeding rather than a rate case. In fact, according to witness Turner, many of the considerations witness Hausman recommends are already evaluated by the Company in its IRP. (*Id.* at 566-67.) For example, the IRP included customer demand, energy efficiency, demand-side management, renewable resources, and traditional supply-side resources in its quantitative analysis and determined that natural gas resources are the least cost alternative for replacement generation. (*Id.* at 566-67, 590.) The Company's Fossil/Hydro Operations organization then used the output from the IRP, in this case a natural gas facility serving as the least cost alternative to a coal-fired plant, in its analyses. (*Id.*) Consequently, if the Company had used other resource alternatives in its analyses, as suggested by witness Hausman, the result would have been even more uneconomical for the customer. (*Id.*) Further, witness Turner stated that witness Hausman seems to primarily focus on the retirement of the coal-fired units while her responsibility is to ensure the Company has sufficient reliable, environmentally-compliant generation to meet the Company's customers' needs and to ensure operational flexibility. (*Id.* at 570-5.) As such, the Company concluded that continued operation of the plant was a better option for customers as opposed to an accelerated retirement and replace scenario. (*Id.*) Witness Turner goes on to acknowledge the Company's obligation to justify its capital investments in rate cases before this Commission and will continue to be prepared to do so. (*Id.* at 570-6.) As such, mandating the performance of retirement analyses prior to the Company's decision to make additional capital improvements, as witness Hausman recommends, is not warranted and could limit the Company's ability to use its best judgment and experience to manage its fleet. (*Id.*)

No other party to this proceeding presented testimony in opposition of the Company's capital investments in its Fossil/Hydro/Solar generation fleet.

The Commission finds and concludes, in light of all the evidence presented, that DE Progress' investment in the Roxboro dry bottom ash system was reasonable and prudent, and results in an asset that is used and useful for its customers. As Company witness Turner testified, the Company's investment in the dry bottom ash system at Roxboro was for the purpose of complying with environmental regulations to ensure the continued operation of the Roxboro plant. To do otherwise would have required the Company to shut down the plant and seek a replacement for the needed generation. In arriving at its decision, the Commission is not persuaded by Sierra Club witness Hausman's assertion that the Company should have considered the accelerated retirement of the Roxboro plant rather than make the investment. The Roxboro plant is an important asset within the Company's fleet to provide customers with low-cost generation and capacity, and the factors provided by the Company clearly indicate that accelerating the retirement of the Roxboro plant would have been operationally and economically imprudent. Further, the Commission agrees with the Company that witness Hausman's recommendations are more appropriately addressed in an IRP proceeding.

The Commission further finds and concludes that Sierra Club's recommendation to the Commission to mandate comprehensive economic and/or retirement analyses for the Company's coal-fired plants is denied. When evaluating whether a capital investment is eligible for inclusion in rate base, the Commission assesses the prudency of the investment and whether the asset is "used and useful." While the Commission appreciates Sierra Club's recommendation, the Commission does not deem it appropriate at this time to mandate retirement analyses be performed by the Company at its generation plants before seeking recovery of investments in the future. The Company is responsible for managing its generation fleet, including what analyses to perform and when to perform them. However, the Commission notes the burden of proof resides with the Company to justify its capital investments, and such analyses may become more relevant in future proceedings.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NO. 56

The evidence supporting these findings and conclusions is contained in the verified Application, the Prepaid Stipulation, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

In its Application, DE Progress seeks approval to launch a Prepaid Advantage Pilot, which is designed for residential customers on non-time of use rate schedules with AMI installed to avail themselves of a prepayment plan that eliminates the need for deposits. (Application at 17.) Similar to the prepaid advantage pilot approved by the Commission for the Company's affiliate, DE

Carolinas, in Docket No. 2015-136-E, eligible customers will be able to: (1) begin service with a lower up front cost, avoiding a traditional deposit if one would otherwise be required; (2) see usage and electricity costs on a daily basis from anywhere via the web or a smartphone; (3) have more choice in payment options, giving the customer the flexibility to determine when to pay and how much based on the customers' lifestyle and receipt of income; (4) potentially avoid bill surprises at the end of an unusual weather month; and (5) if service is disconnected, have it restored faster through remote capabilities. (*Id*. at 17-18.) Company witness Don Schneider, Jr. testified about the benefits and launch procedure for the Pilot.

The Prepaid Stipulation provides that the Company withdraws from Commission consideration the Prepaid Pilot. The Parties agreed that all testimony and evidence regarding the Prepaid Pilot be moved to the new docket to ensure efficiency and that all parties to Docket No. 2018-318-E, who have expressed any position on the Prepaid Pilot, shall automatically be granted intervenor status. The Parties further agreed that provided the Company implements the Pilot in the same manner that DE Carolinas implements its Pilot program, the ORS will (a) not object to the Company's Prepaid Pilot and (b) not oppose the Company seeking expedited review of its Pilot.

The Commission finds and concludes that the Prepaid Stipulation is just and reasonable to all parties considering all the evidence presented, and is therefore approved.

EVIDENCE FOR FINDINGS AND CONCLUSIONS NOS. 57-58

The evidence supporting these findings and conclusions is contained in the verified Application, the 2018 DE Progress Rate Case Stipulations, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Under South Carolina law, the Commission is vested with the authority to fix just and reasonable utility rates. S.C. Code Ann. §§ 58-3-140, 58-27-810. Under this statute, the Commission has traditionally adhered to the following principles:

> (a) the revenue-requirement or financial-need objective, which takes the form of a fair-return standard with respect to private utility companies; (b) the fair-cost-apportionment objective, which invokes the principle that the burden of meeting total revenue requirements must be distributed fairly among the beneficiaries of the service; and (c) the optimum-use or customer-rationing objective, under which the rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between cost incurred and benefits received.

Bonbright, *Principles of Public Utility Rates*, 292 (1961). These criteria have been used by the Commission in previous cases and are again utilized here. (*See, e.g.* Order No. 2013-661, at 26-27; Order No. 2005-2, at 105; and Order No. 2003-38, at 76).

Once a utility's revenue requirement has been determined, a rate structure must be developed that yields that level of revenues. The basic objective of a rate structure is to enable a company to generate its revenue requirement without unduly burdening one class of customer to the benefit of another. Proper rate design results in revenues where each customer, and each customer class, pays, as close as practicable, the cost of providing service to them.

The Commission approves the Company's proposed revenue increase of approximately $68,501,000 annually, as set forth in Hearing Ex. 17 (Bateman Rebuttal Exhibit 1), adjusted per the terms of the 2018 DE Progress Rate Case Stipulations approved herein.[81] The approved revenue increase is based on the following amounts of test year pro forma operating revenues,

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[81] The base revenue increase does not include the impact of EDIT Rider year 1 reduction of ($12,802,000) as calculated in Hearing Ex. 16 (Bateman Revised Second Supplemental Ex. 3, p. 2).)

operating revenue deductions, and original cost rate base (under present rates), which are to be used as the basis for setting rates in this proceeding: $629,237,000 of operating revenues, $515,557,000 of operating revenue deductions, and $1,512,508,000 of original cost rate base, adjusted per the terms of the 2018 DE Progress Rate Case Stipulations approved herein.

DE Progress' continued operation as a safe, adequate, and reliable source of electric service for its customers is vitally important to the Company's individual customers, as well as to the communities and businesses served by the Company. DE Progress presented credible and substantial evidence of its need for increased capital investment to, among other things, maintain and increase the reliability of its system and comply with environmental requirements. Based on all of the evidence, the Commission finds and concludes that the revenue requirement, rate design, and the rates that will result from this Order strike the appropriate balance between the interests of DE Progress' customers in receiving safe, reliable, and efficient electric service at the lowest possible rates, and the interests of DE Progress in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the revenue requirement and the rates that will result from that revenue requirement established as a result of this Order are just and reasonable.

IT IS THEREFORE ORDERED THAT:

1. The Nucor Stipulation entered into by DE Progress and Nucor; the ORS Stipulation entered into by DE Progress and the ORS; the Prepaid Stipulation entered into by DE Progress and the ORS; and the Non-allowables Stipulation entered into by DE Progress and the ORS (collectively the "DE Progress 2018 Rate Case Stipulations") are hereby approved in their entirety;

2. DE Progress shall be allowed to increase its rates and charges effective for service rendered as of June 1, 2019 so as to produce an increase in annual revenues from base rates for its South Carolina retail operations of $68,501,000, adjusted per the terms of the 2018 DE Progress Rate Case Stipulations approved herein, based upon the adjusted test year level of operations;

3. The calculation of the base rates required to generate a $68,501,000 revenue increase, adjusted per the terms of the 2018 DE Progress Rate Case Stipulations approved herein, shall be established based on a 10.50% ROE, 4.16% cost of debt, and capital structure of 53% equity and 47% debt;

4. The accounting and pro forma adjustments in Hearing Ex. 17 (Bateman Rebuttal Ex. 1), adjusted per the terms of the 2018 DE Progress Rate Case Stipulations approved herein, are adopted;

5. DE Progress shall recalculate and file the annual revenue requirement with the Commission within five days of the issuance of this Order, consistent with the findings and conclusions of this Order and the 2018 DE Progress Rate Case Stipulations. The Company shall work with the ORS to verify the accuracy of the filing.

6. The Company's proposed EDIT Rider, as adjusted per the terms of the Nucor Stipulation, is approved;

7. The appropriate annual revenue requirement for the first year shall be reduced by the EDIT Rider decrement of ($12,802,000);

8. The Company shall file the EDIT Rider amounts, along with the spread to the classes and derivation of the rate, for each subsequent year with the Commission in this docket by March 31, for rider rates effective June 1;

9. The rate design, rate schedules, and revenue allocation proposed by the Company in its Application, and in its testimony and exhibits filed in this proceeding, as modified by the changes to the Basic Facilities Charges agreed upon in the Company's March 26, 2019 letter and the Nucor Stipulation pertaining to the LGS-CUR-TOU rate schedule, are approved;

10. The modifications to DE Progress' Service Regulations, as set forth in the testimony of Company witness Wheeler and Exhibit B to the Application, are approved;

11. The Company shall modify its Basic Facilities Charges in accordance with its letter filed in this docket on March 26, 2019;

12. DE Progress shall recover the actual CCR compliance costs relating to coal ash basin closure it has incurred during the period from June 30, 2016 through December 31, 2018 in rates, amortized over a five-year period, and the Company shall earn a return on the unamortized balance at the overall rate of return approved in this case through inclusion in rate base;

13. DE Progress' request to defer CCR compliance spend related to coal ash basin closure beginning January 1, 2019, the depreciation and return on CCR compliance investments related to continued plant operations placed in service on or after January 1, 2019, and a return on both deferred balances at the overall rate of return approved in this case is approved;

14. DE Progress shall recover its deferred costs relating to the Harris COLA, Fukushima/Cybersecurity and GridSouth, over an amortization period of five years, and the Company shall earn a return on the unamortized balance of the Fukushima/Cybersecurity and GridSouth deferrals at the overall rate of return approved in this case through inclusion in rate base;

15. DE Progress' request for an accounting order to establish a regulatory asset at the time of the Asheville plant's retirement for the remaining net book value, and to defer to this regulatory asset any costs related to obsolete inventory, net of salvage, at the time of retirement, is approved;

16. DE Progress shall recover its deferred costs relating to the implementation of AMI meters, amortized over three years, and the Company shall earn a return on the unamortized balance at the overall rate of return approved in this case through inclusion in rate base;

17. DE Progress' request for an accounting order to defer the financial effects of the incremental O&M expense and the depreciation expense incurred for its AMI meters installed after December 31, 2018, including the carrying costs on the investment and its deferred costs at the Company's WACC is approved;

18. DE Progress shall recover its deferred costs relating to grid reliability, resiliency, and modernization work, amortized over two years, and the Company shall earn a return on the unamortized balance at the overall rate of return approved in this case through inclusion in rate base;

19. In accordance with the Stipulation approved by the Commission in Order No. 2019-26H in this docket, the Company shall defer into a regulatory asset account

all GIP-related costs until the underlying costs and proposed recovery may be considered for recovery in the Company's next general rate proceeding;

20. In accordance with the ORS Stipulation, DE Progress shall recover the incremental rate case expenses incurred for this case through December 31, 2018 as calculated by the ORS, to be amortized over a period of five years and the Company shall earn a return on the unamortized balance at the overall rate of return approved in this case through inclusion in rate base;

21. The Company will continue to defer its rate case expenses incurred after December 31, 2018, and will continue to send invoices to ORS to audit per the terms of the ORS Stipulation;

22. DE Progress' request to recover its litigation expenses related to coal ash litigation and insurance recoveries is approved;

23. DE Progress' request to recover its litigation expenses and ongoing payment obligation costs related to the litigation with CertainTEED is approved;

24. In accordance with the ORS Stipulation, the Company shall use a five-year average (removing the highest and lowest years) without any inflation adjustment for its storm normalization adjustment;

25. The Company will examine the feasibility and customer benefits of a storm damage reserve fund and shall provide a proposal to ORS to evaluate before the Company's next base rate case per the ORS Stipulation;

26. DE Progress shall remove the inflation adjustment to non-labor O&M per the terms of the ORS Stipulation;

27. DE Progress shall recover its deferred costs relating to Customer Connect, amortized over three years, and the Company shall earn a return on the unamortized balance at the overall rate of return approved in this case through inclusion in rate base;

28. DE Progress shall recover its forecasted Customer Connect O&M costs and is required to report to the Commission the actual Customer Connect O&M costs incurred on an annual basis;

29. DE Progress' request to adjust depreciation and amortization expenses to establish a reserve for end-of-life nuclear expenses, as modified by the ORS Stipulation, is approved;

30. DE Progress shall adjust its nuclear material and supplies inventory to remove nuclear materials and supplies inventory at the Company's nuclear plants that has remained in a hold status for greater than four years per the ORS Stipulation;

31. The approved base fuel and fuel-related cost factors (excluding gross receipts tax and regulatory fees), by customer class, are as follows: an increment of 3.087 cents per kWh for the Residential class, an increment of 2.801 cents per kWh for the General Service-Non Demand class, an increment of 2.366 cents per kWh, 89 cents per KW[82] for the General Service- Demand class, and an increment of 2.366 cents per kWh for the Lighting class;

32. The Company's request to revise customer rates based on the revised depreciation study, filed by the Company as Doss Exhibit 2 (part of composite Hearing

[82] The environmental DERP avoided costs, and capacity-related components of fuel costs factors are billed on a cents per KW basis for General Service-Demand customers.

Ex. 21), and depreciation rates filed by the Company as Doss Exhibit 3 (part of composite Hearing Ex. 21) is approved;

33. DE Progress' proposal to pay convenience fees collected by third-party vendors for payments made by credit card, debit cards, and ACH payments on behalf of its residential customers and to recover the costs of these convenience fees as part of the Company's cost of service based on the amount of 2018 actual transactions per the ORS Stipulation is approved;

34. SC NAACP et al.'s proposal that DE Progress should be required to provide detailed monthly residential and low-income customer usage data by zip code in a format accessible to the public is denied;

35. Sierra Club's proposal that the Commission disallow the Company's $100 million investment in the dry bottom ash system at Roxboro and require the Company to undertake comprehensive economic and retirement analyses prior to making capital investments at its coal-fired plants is denied; and

36. This Order shall remain in full force and effect until further Order of the Commission.

BY ORDER OF THE COMMISSION:

Comer H. Randall, Chairman

ATTEST:

Justin T. Williams, Vice Chairman